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Sixth Clean Coal Technology Conference

PROCEEDINGS

Volume I - Policy Papers

Reno, Nevada

April 28-May 1, 1998

Clean Coal for the 21st Century: What Will It Take?

The Sixth Clean Coal Technology Conference focused on the ability of clean coal technologies (CCTs) to meet increasingly demanding environmental requirements while simultaneously remaining competitive in both international and domestic markets. Conference speakers assessed environmental, economic, and technical issues and identified approaches that will help enable CCTs to be deployed in an era of competing, interrelated demands for energy, economic growth, and environmental protection. Recognition was given to the dynamic changes that will result from increasing competition in electricity and fuel markets and industry restructuring, both domestically and internationally.

Energy use, critical to economic growth, is growing quickly in many regions of the world. Much of this increased demand can be met by coal with technologies that achieve environmental goals while keeping the cost per unit of energy competitive. Private sector experience and results from the CCT Demonstration Program are providing information on economic, environmental, and market issues that will enable conclusions to be drawn about the competitiveness of the CCTs domestically and internationally.

The industry/government partnership, cemented over the past 11 years, is focused on moving the technologies into the domestic and international marketplace. The Sixth Clean Coal Technology Conference provided a forum to discuss benchmark issues and the role and need for these technologies in the next millennium.

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INTERNATIONAL BUSINESS FORUM BRUNCH

ELECTRIC POWER IN LATIN AMERICA AND THE CARIBBEAN:

PROSPECTS FOR CLEAN COAL TECHNOLOGIES

I would first of all like to present apologies from the Executive Secretary of OLADE, who was unable to attend the present event due to a meeting being held today in Quito, Ecuador that brings together representatives from the various countries that are members of OLADE's Follow-up and Monitoring Committee.

The Executive Secretary, Mr. Luiz A. M. da Fonseca, would very much have liked to be here with you today to impart his viewpoints on a topic that has top priority on our energy agenda, that is, the development of clean coal technologies, especially for electric power generation, and in a broader sense, the linkage between energy activities and the environment, an issue which is certainly being taken quite seriously by the international community.

I do not intend my presentation to reflect the opinion of an expert in clean coal technologies. The majority of the present audience is better acquainted with this topic, and therefore I will restrict myself to sharing with you some thoughts about the future development of energy activities in Latin America and the Caribbean, if not during the 21st century as announced by the Conference, at least for its first decade, as well as about the role that these technologies could play in this process. I would like to focus on some of the basic orientations set forth by the Report of the Working Group to Promote Clean Energy Technologies set up within the framework of the Hemispheric Energy Symposium and headed by OLADE itself, which relied on the participation of Argentina, Bolivia, Chile, Mexico, Venezuela, and the U.S. Department of Energy.

I will also describe experiences that have shaped OLADE's perception regarding the topic we are considering today.

I would like to briefly highlight some figures to help us get a better picture of the region's current economic situation. Over the past year, the economy of Latin America and the Caribbean achieved what, in the opinion of ECLAC, is its best performance in the last quarter century. Indeed, the recovery observed since 1996 became even more evident in 1997 when average growth rose to 5.3%, which compares favorably with the rate of 3.2% recorded during the first half of the nineties and, even more so, with the so-called "lost decade" of the eighties, which recorded a negligible growth of 0.9%.

The per capita GDP last year rose to 3.6%; and today it is 13% higher than it was at the start of the decade. Eight countries in the area had an expansion of between 6 and 8%, seven economies showed a growth rate of between 4 and 6%, whereas nine achieved rates close to 3%.

Price performance has also been encouraging. For the fourth consecutive year, consumer prices in 1997 displayed a downward trend, an average of 11%, which has been the lowest rate in several decades. For the sake of comparison, suffice it to say that the largest economies of the region, at the start of the decade, had rates over 1,000%, and even in 1993 the average for the region was 890%, after which a noteworthy descent began for the ensuing three years: 338%, 26%, and 18%.

Although last year regional urban unemployment declined slightly, from 7.7% to 7.5%, rates are still high compared to historical records. Mexico and Argentina have managed to avoid the general trend, and their economic recovery has led to greater generation of employment. As the economic crisis is being overcome, high inflation is being curtailed, and the recessionary impacts of stabilization programs are declining, higher real salaries are beginning to appear.

International trade of the region's economies is recording greater impetus than the economy as a whole, especially in terms of imports, which last year grew by 18% due to recovery of domestic demand and real appreciation of national currencies, whereas exports rose by 11%.

In 1997, LAC's current account deficit rose from US$35 billion to US$60 billion, accounting for 3% of the region's GDP. This is the result of the high deficits of Brazil, Argentina, and Mexico, as well as Venezuela's lower surplus.

Finally, capital inflows have kept up a steady pace, although over the last quarter of 1997 this trend has slowed down, as a result of the financial turmoil in the majority of Asian markets which has exerted its impact on the LAC region. A large share of external financing involved direct investments, which amounted to US$44 billion, with historical peaks in Brazil, Mexico, the Dominican Republic, and Venezuela. Direct foreign investment accounted for more than 3% of GDP in seven economies of the region.

Although it is certain that, for this year, forecasts are less optimistic partly due to competition from Asian products which are now more competitive, it is clear that the region as a whole has a sounder economic structure, which will better enable it to take up the economic challenges of coming years.

What are the future challenges for the region of Latin America and the Caribbean?

Forecasting exercises being conducted in OLADE indicate that, during the period 1995-2015, the average GDP growth rate will amount to about 4%. On the basis of this scenario, the total demand for energy will grow, during this period, from 2,808 to 5,093 million barrels of oil equivalent, which means an annual average growth rate of 3.02%. The highest rates will be recorded by natural gas (4.26%), electricity (3.6%), and oil and derivates (3.17%). Over the same period, coal demand will grow at an average rate of 2.9%. It is therefore clear that total energy demand growing at rates that are lower than those of the economy as a whole will lead to lower energy intensity.

Regarding the electric power sector, the LAC region will have to duplicate its power generation capacity, from 164.4 GW in 1995 to 331.6 GW by the year 2015. Whereas at the start of this period almost two thirds were accounted for by hydropower, by the end of the period, this share will have declined to less than half (48.4%), giving way to higher capacity from thermoelectric plants, especially those using natural gas, which will grow from 33.1% to 49.9% between 1995 and 2015. Electricity consumption, however, will grow over the same period from 666.8 TWh to 1,381.8 TWh, that is, an annual average expansion rate of 2.91%.

The power generation capacity mix reflects an abundance of hydro resources in the region. The favorable financial climate of the sixties and seventies was a decisive factor for the notable development of hydropower installations. Although it is true that this source of electric power has been viewed as an option for sustainable development, long construction periods and the large amounts of financial resources required for their construction are certainly elements that will contribute to reducing the role of hydropower in the future for the Latin American region as a whole, despite the relatively low tapping of hydro potential. The diversification of primary energy supply and the reliability of power generation sources are issues being considered by the region's energy policymakers. A rise in private-sector capital for the development of electric power infrastructure clearly fosters preference for smaller-scale projects that have shorter capital recovery periods. In general, it can be asserted that the major factors that will be determining the region's electric power sector structure and development are:

- Sector deregulation processes.
- Leading role of private-sector financing for developing additional capacity in the electric power system.
- The need to ensure that this development will be compatible with environmental preservation and improvement demands.
- The need for more open economies, such as the current economies of Latin America and the Caribbean, to include competitiveness and energy supply security as crucial elements for the decision making to develop additional capacity. This explains the growing penetration of natural gas in many countries of the region and the

subordinate participation of other sources, such as coal, which will have to meet more stringent environmental regulations and compete with other fuels.

For a proper understanding of the role that coal is to play as an input for power generation in Latin America, it should be recalled that, compared with world figures for both coal reserves and consumption, this energy product can only play a marginal role in the region. A large part of the additional consumption of coal for power generation is limited to plants whose construction has already been contracted.

Another obstacle to the further development of coal that should be considered is the poorly developed transport infrastructure for coal and the additional investments that would be required to enlarge and upgrade it. Supply security concerns could lead to the recommendation that, for sector policy reasons, supply diversification should be considered and opportunities provided for coal development, especially the use of domestic coal.

Some examples could better illustrate the current situation of electric power sectors in different countries of the region and the possibility of developing capacity on the basis of coal use. In Mexico, natural gas is the preferred option, both for its lesser environmental impact and lower generation costs. This is a well-defined position taken by sector authorities, at least with respect to the additional capacity aimed at providing public service. Nevertheless, if an approach aimed at ensuring greater diversification is incorporated to avoid excessive dependence on hydrocarbons to generate electricity, one alternative to the combined cycles that will be installed on the coast of the Gulf of Mexico or the Pacific coast could be dual-fuel stations capable of burning imported coal. There could be yet another approach that could prevail among external producers whose power generation is not aimed at providing public service. For example, a large private concern that owns coal mines in northern Mexico is already developing a coal-fired electric power project, with a capacity of 180 MW, which would start up before the year 2000.

In Colombia, it is clear that a decision has been taken to allow a broader participation of coal as an energy source to increase power generation capacity over a time period that extends to the year 2010. Despite this, it must be underscored that natural gas will account for the largest energy source for electric power generation up to the year 2010. Nevertheless, our impression is that, although complementary assessments are still required, the use of coal-fired power generation provides clear economic and social benefits since, according to ECOCARBON, "the use of an abundant, low-cost fuel like coal that offers high levels of reliability and availability, ensures stability of electric power production costs over the long term and contributes to a greater generation of employment, compared to other thermoelectric generation options."

As for Brazil, it can be said that the greater use of coal has been hampered by its high ash content and the high associated transport costs. The coal-fired stations that are considered viable, are those that use coal on the production site. The characteristics of Brazil's electric power system, which mostly tapped the huge hydropower potential of the country, meant that, for practical reasons, a greater expansion of its thermoelectric capacity was limited and that the latter was used for complementary purposes, involving the better use of the energy available from hydropower stations. On the basis of conclusions presented just last week in Rio de Janeiro, within the framework of the project that OLADE is implementing with the Economic Commission for Latin America and the Caribbean (ECLAC) and the German Technical Cooperation Agency (GTZ), "the growing concern on the part of Brazilian society about environmental impacts stemming from the energy sector is a new challenge for the coal sector, which will have to incorporate new technologies into its facilities. As a result, the development of a coal center in the region of Candiota, where the most economically attractive deposits are located, seems to be the best course to adopt. This center would help to maximize economies of scale, indispensable to ensure the competitiveness of the coal production chain. Likewise, the location of Candiota at the crossroads of the large interconnected markets of MERCOSUR will facilitate finding ways to explore the optimal development of production facilities and the load curves of the countries that are part of this market."

Beyond these three cases, which illustrate, at least partially, the potential of coal in electric power generation in the Latin American region, it should be recalled that, as part of the tasks that were assigned to the Working Group on Clean Technologies in the framework of the Hemispheric Energy Symposium, OLADE conducted a survey that included a wide sampling of countries to learn about the criteria used to select clean technologies. The results of this survey, as indicated in the above-mentioned Working Group Report, are that:

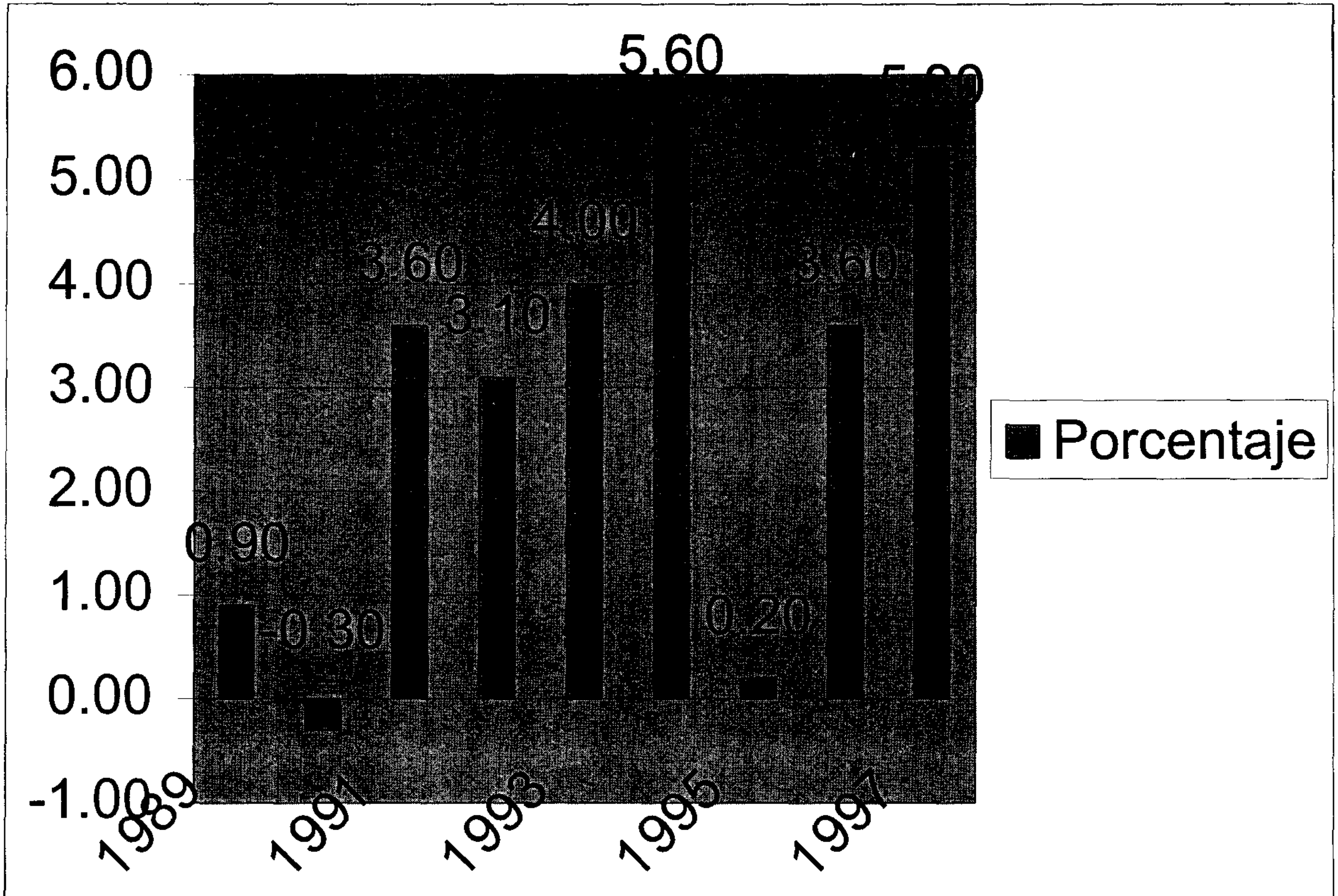
- The majority of the countries believe that availability and cost of the resources are fundamental decision making factors.

- In those countries with extensive private-sector participation in power generation, it is evident that these private players are in charge of taking the decisions to adopt these technologies. In these cases, cost is the decisive factor in selecting the technology.

- Only half the responses included environmental impact as a decision-making element.

- The widespread perception is that the barriers that have to be overcome to ensure that clean technology options will be adopted are mainly economic, due to the need to incorporate competitiveness and the financial risk associated to investment recovery, as well as regulatory schemes with respect to tariffs, incentives for investment, or operating constraints.

Summarizing, I would say that, even when coal will not play a major role as a source for electric generation in Latin America, there are still opportunities assuming that projects are to be developed in specific coal producing regions or as a consequence of a diversified policy trying to avoid an excessive depends on a single fuel as energy source for electricity generation.


6.00
5.00
4.00
3.00
2.00
1.00
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-1.00
1989
1991
1993
1995
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-0.30
3.60
3.10
4.00
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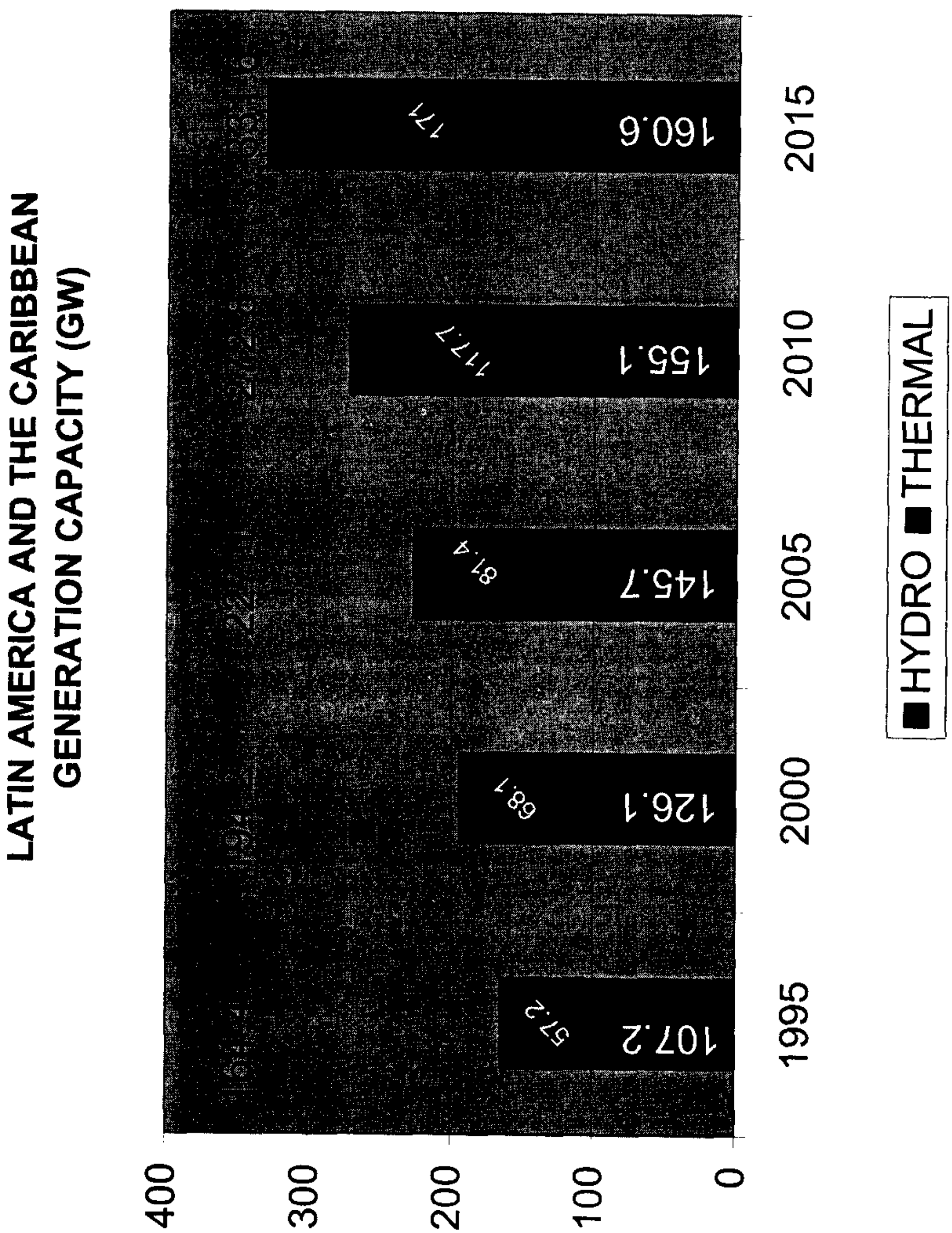
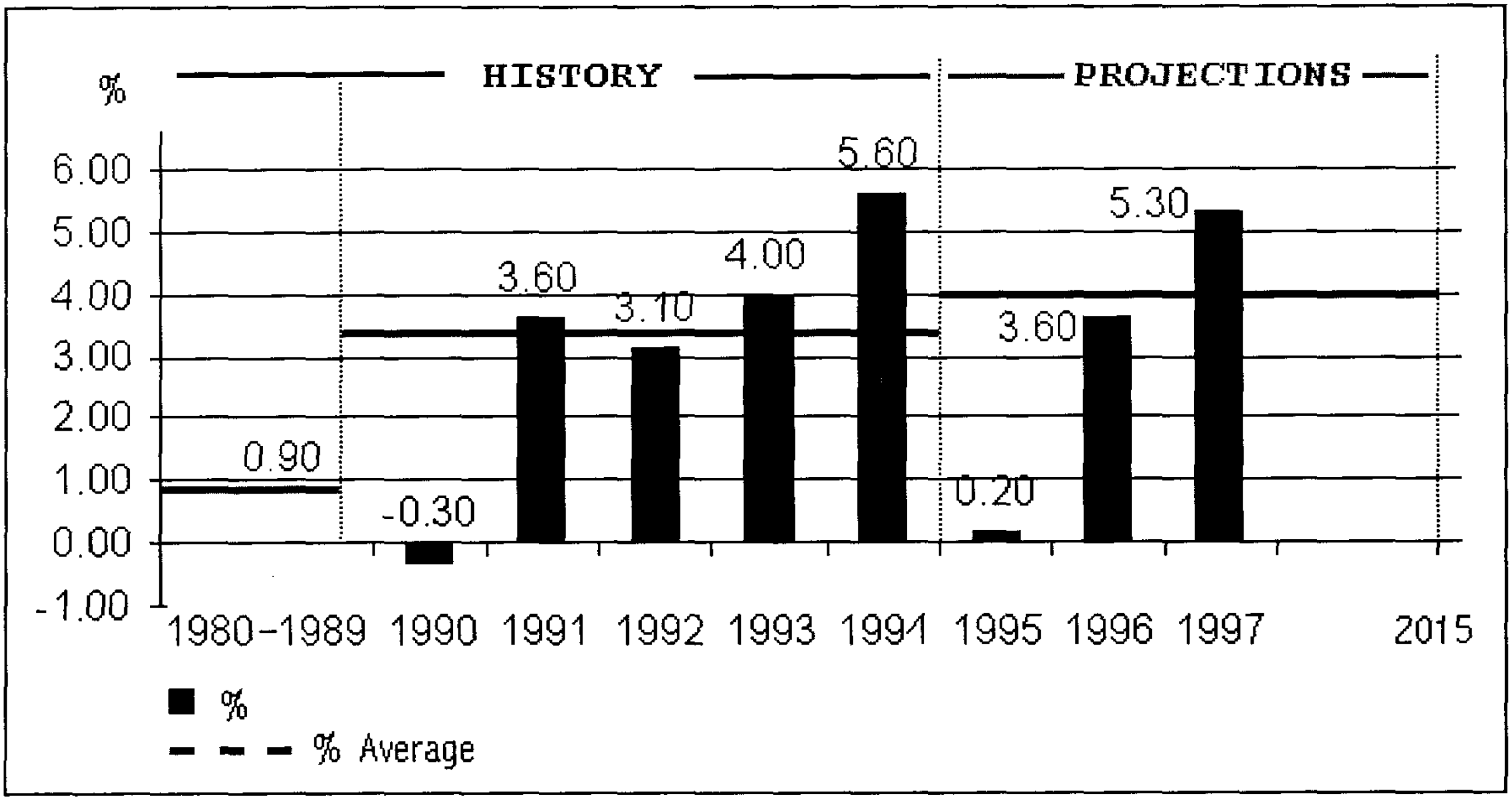
Porcentaje

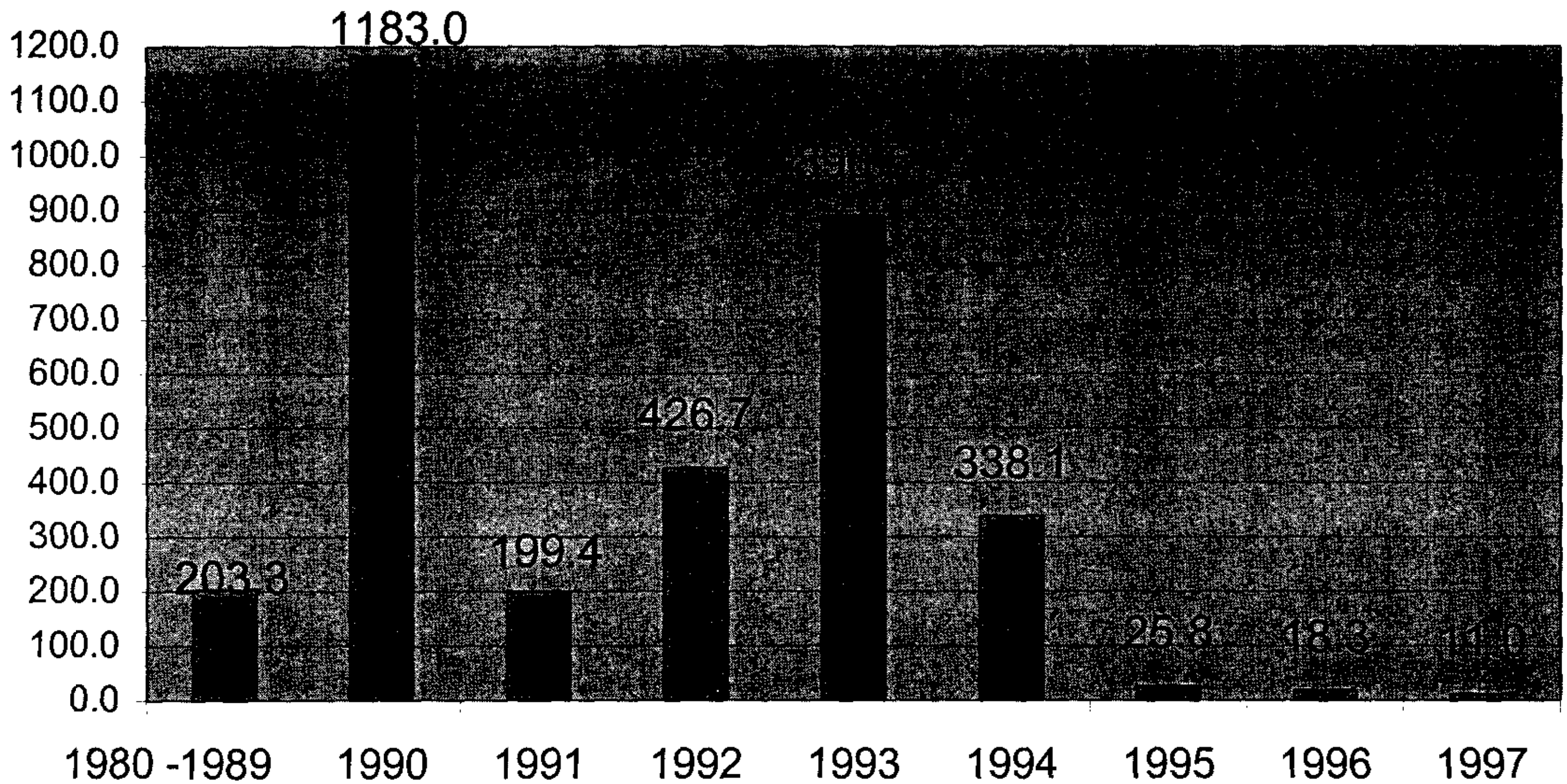

LATIN AMERICA AND THE CARIBBEAN
GENERATION CAPACITY (GW)
400
300
200
100
0
107.2
57.2
126.1
68.7
145.7
81.4
155.1
117.7
160.6
171
1995
2000
2005
2010
2015
HYDRO
THERMAL

LATIN AMERICA AND THE CARIBBEAN - GROSS DOMESTIC PRODUCT

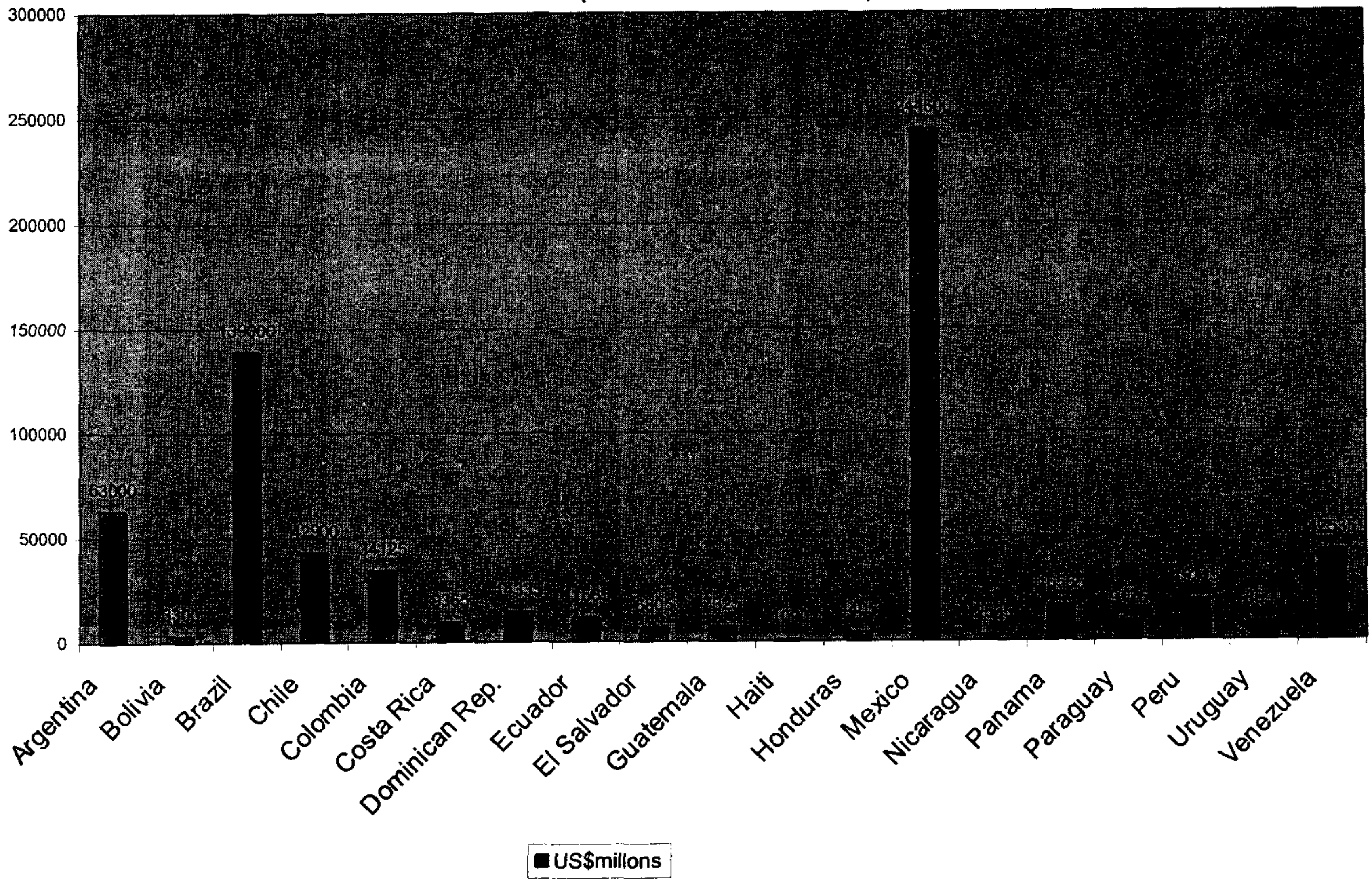
ANNUAL GROWTH RATE



LATIN AMERICA AND THE CARIBBEAN CONSUMER PRICE INDEX (%)



LATIN AMERICA'S TOTAL TRADE (EXPORTS + IMPORTS)



PRESENT AND FUTURE CLEAN COAL TECHNOLOGIES POSITION OF THE EUROPEAN UNION

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ABSTRACT

Coal is the world's most abundant energy source, and can be used in a clean and cost effective manner. Even though the percentage share of coal as a fuel for power generation will decrease during the coming decades, this use of coal will still increase in absolute terms and coal will maintain its important position in this sector. This fact underlines strongly the need for clean and efficient coal technologies. This is especially true for emerging and developing countries.

CCT's are needed firstly for new power plants and secondly because many old units will reach the end of their designed life time in the near future. Cost effective technologies for the retrofitting of such units are required, and it seems clear that the main market will not be in Europe or the OECD but in countries outside the OECD. Most of the necessary technologies are state of the art, but offering those technologies at low cost is still a big challenge that should be complemented by significant parallel initiatives to introduce more advanced ones.

The European Union is in a good position to offer all state of the art technologies for conventional and advanced clean use of coal in power generation at competitive prices. Furthermore, the development of more advanced generating technologies is well underway and these will be available on the marketplace in the near future according to the last developmental results.

The paper deals with market opportunities of state of the art and advanced clean coal technologies and displays the recent state of RTD work on the related field in the European Union (Following the conventions of the European Commission RTD includes Demonstration and Dissemination).

I THE NEED OF CLEAN COAL TECHNOLOGIES

The world primary energy demand is expected to continue to grow steadily within the next decades, as it has grown in the past. The reasons are the increasing world population and a growing energy demand per capita world wide. It can not be expected that the energy demand per capita in the developed countries will decrease significantly, compensating the growth of the emerging economies. This is reflected in all recent studies concerning future energy demand and leads to conclusions about the development of energy demand as, e.g., in the 2020 Study of the European Commission (see Figure 1) and in similar publications from the IEA, WB, WCI, WEC, etc., which display, in principle, the same trends.

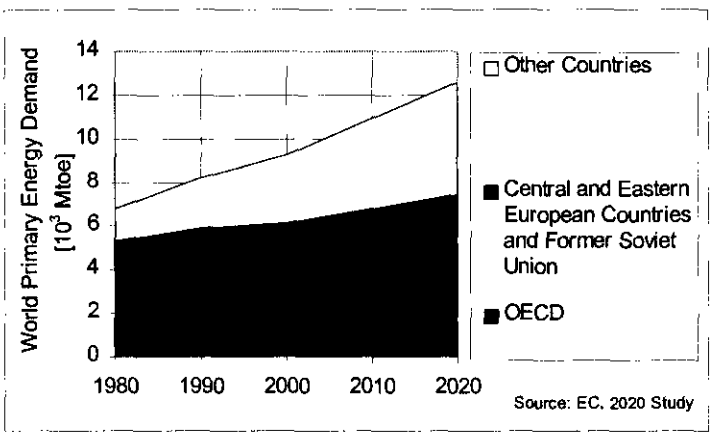


Figure 1 World Primary Energy Demand

The breakdown of the world primary energy demand by energy sources (see Figure 2) shows the share of Solid Fuels (mainly coal but also wood, peat, etc.) remaining constant or slightly falling until the year 2020. Also, the share of oil and gas is constant in that time period but seeing gas taking over significant shares from oil. The remainder is provided by nuclear and renewable energy sources, including hydropower. Nuclear is falling slightly. The renewable sources are slightly increasing, but not reaching a significant level of the total energy demand. This is expected to be true also for the rest of the next century.

Correlating the relative share of energy sources with the primary energy demand, it becomes clear that even a constant share leads to a significant increase in absolute values of the related source (see Figure 2). Looking, for example, at the coal share, which will probably remain more or less constant during the period up to 2020, this would mean an increase from 2190 Mtoe in 1990 to 3024 Mtoe in 2020, equivalent to about 38%.

Coal is available in abundance and at a low and stable price. Consequently, it is clear that coal is likely to continue to be one of the dominant sources of energy for energy actors in the medium to long term. Therefore one of the highest priorities in energy conservation and reduction of pollution will apply to coal-burning activities and, in particular, to power generation in the future.

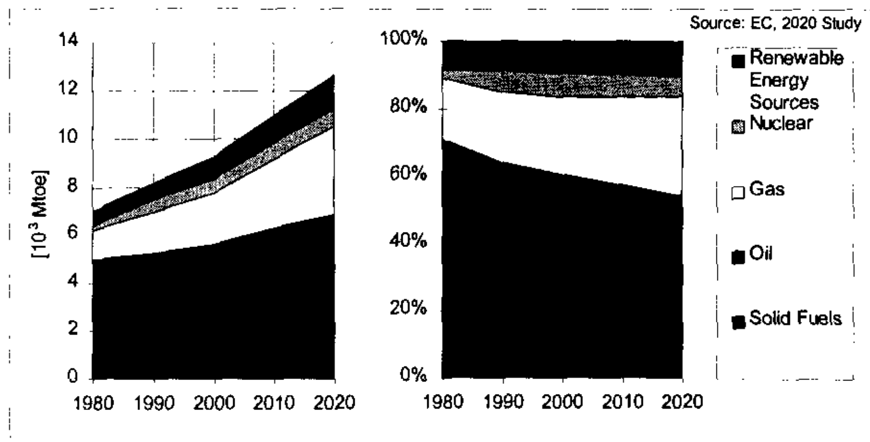


Figure 2 World Primary Energy Demand by Fuel (Absolute values and rel. share)

Besides many other important uses, utilisation of coal is most significant in electricity generation, steel and cement manufacture, and industrial process heating (Figure 3). More than half of total world coal production currently provides some 40% of the world's electricity. Many countries are heavily dependent on coal for electricity, including in 1994: Poland (96%), South Africa (90%), Denmark (82%), Australia (78%), Greece (74%), China (70%), Germany (57%) and the USA (53%).

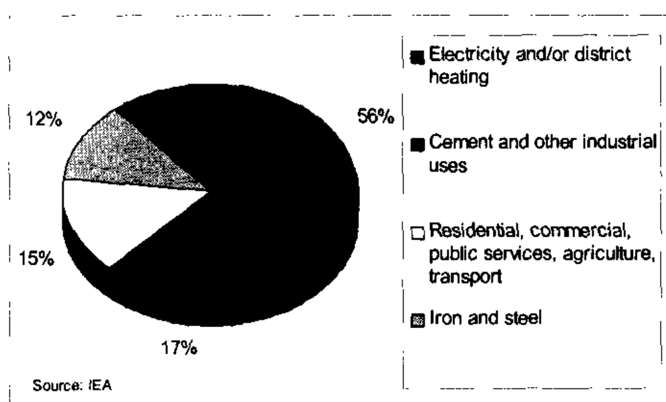


Figure 3 Use of hard coal (1994, 3,527 Mt)

Neglecting nuclear and hydro power, Figure 4 shows the future share of fuels for thermal power generation expected by the EC 2020 study.

As can be seen from the graph solid fuels will continue to provide the biggest share of fuel input for power generation with a substantial increase in absolute numbers.

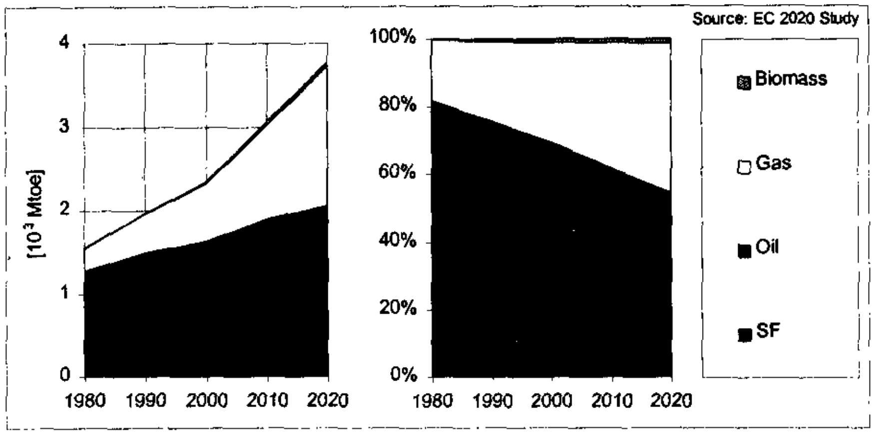


Figure 4 Thermal Power Generation - Fuel Input (Absolute values and rel. share)

II CLEAN COAL TECHNOLOGIES - ADVANCED PROCESSES AND COMPONENTS

Coal can not achieve its prominence without the development of clean, efficient and cost-effective technologies.

In the last two decades after the oil price crisis, several advanced power plant and solid fuel firing concepts have been studied in respect of their application. Special emphasis has been placed on such technologies that are expected to be capable of meeting the stepped-up requirements in terms of emission control and efficiency. Special emphasis is also given today also to the reduction in costs both investment costs (ECU/kW, USD/kW) and generation costs (ECU/kWh, USD/kWh). There are in particular the following concepts that are deemed suitable to fulfil these criteria and are available for industrial application or are expected to be available for industrial-scale demonstration in the foreseeable future or on a longer-term basis.

- Advanced pulverised coal-fired boilers (PCF)
- Atmospheric fluidised-bed combustion (AFBC)
- Pressurised fluidised-bed combustion (PFBC)
- Integrated gasification combined-cycle systems (IGCC)
- Pressurised pulverised coal combustion (PPCC)
- Integrated gasification fuel cell systems (IGFC)
- Magnetohydrodynamic electricity generation (MHD).

These fundamental concepts include a great number of variants, which cannot be dealt with in detail here. This refers, e.g., to different concepts of the fluidised-bed technology and a multitude of IGCC concepts. So, in Europe various gasification processes (e.g. Shell, Prenflo, Lurgi-BGL, HTW) have been developed for different fuels and applications. Now different configurations in respect of fuel utilisation, gasification agents and integration of the gas turbine are being investigated for the combined-cycle processes (e.g. air blown gasification cycle/topping cycle, integrated drying and gasification combined cycle/IDGCC, humidified air turbine/HAT). In order to improve efficiency of the conventional steam cycle (Rankine cycle) applied in most of the electricity generation processes, alternative cycles (e.g. Kalina cycle) are being investigated.

There is a number of components and process steps that are of primary importance to the development of advanced solid fuel-based electricity or combined heat and power (CHP) generation systems, either because they have multi-purpose applications in various advanced systems or because they are key components to achieve a high efficiency target. These techniques are:

- Drying processes for low rank-coals, biomass and recovered fuels
- Co-utilisation of coal, biomass and recovered fuels
- Low-cost combined heat and power generation (CHP)
- Hot gas clean-up (HGCU) for solid fuel-based combined-cycle electricity generation
- Gas turbine development for coal-derived fuel gas or flue gas
- Advanced control systems.

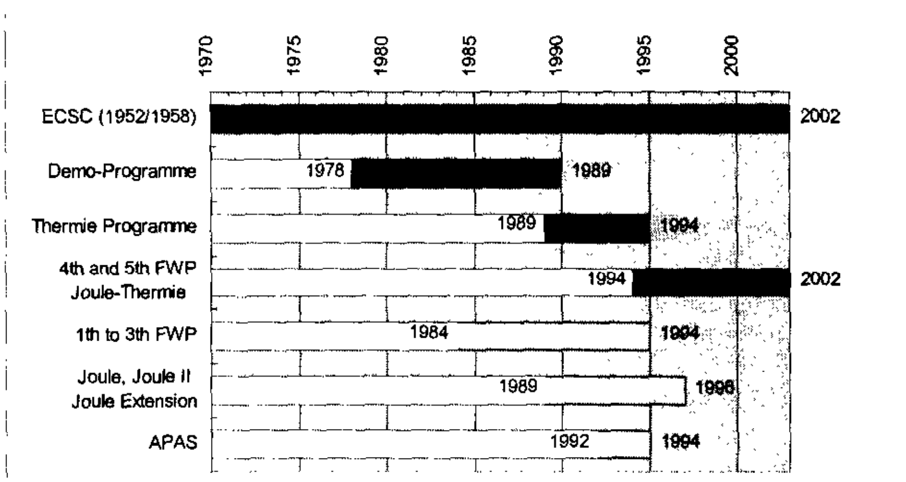
Some of these processes, technologies and components are described and discussed in more detail later in this paper.

III EU CLEAN COAL TECHNOLOGIES SUPPORT PROGRAMMES

The European Community has a long history of support for research, development and demonstration of energy technologies and especially into the production and utilisation of solid fuels.

Figure 5 gives an overview of the energy related programmes of the European Community which are briefly highlighted in the following paragraphs.

Until the early 1970's the support was given almost entirely through the European Coal and Steel Community (ECSC) treaty which commenced in 1952. The research programme on coal started in 1958 and is directed principally towards supporting the production and utilisation of (hard) coal indigenous to Member States of the Community.



Note: Bar for ECSC R&D activity fore-shortened. The treaty was signed in 1952, coal research projects started in 1958

Figure 5 Overview of Energy related Programmes of the European Union

The topics covered by the ECSC coal research programme are sub-divided into mining engineering and product upgrading.

Support for the coal research programme was traditionally about 50 MECU[1] (USD 58 M)per year but has varied between 20-30 MECU (USD 23 M - 35 M) in recent years. Originally two-thirds of the available funding went to projects concerned with mining/production however with the decreasing production of coal in the EU about two-thirds of the funding is now applied to coal use and environmental aspects.

The oil crises in the '70's led to the setting up of the EC Energy Demonstration Programme, implemented in 1978, within which was support for the demonstration of coal liquefaction and gasification technologies (LG). This programme was widened in 1983 to include combustion (CS).

Over the period from 1978 to 1989, the EC made grants available totalling about 300 MECU (USD 348 M). About 40 million (USD 46.5 M) went to support liquefaction projects, while about 70 million (USD 81 M) was used to support combustion projects and about 150 million ECU (USD 174 M) was spent on coal gasification and combined cycle projects. It is the work on the development of pressurised gasifiers that has facilitated the further development of the latest "Clean Coal" gasification technology. Some 40 million (USD 46.5 M) was spent on other aspects, e.g., on the demonstration of underground gasification and environmental abatement technologies.

The Demonstration Programmes LG and CS were followed by the THERMIE Demonstration Programme. The THERMIE programme, ran from 1990 to 1994 and was set up with a budget of 700 MECU (USD 812 M), to be divided between work in three main areas: the rational use of energy (RUE), new and renewable energies (RES) and fossil fuels (FF) which are subdivided into hydrocarbon exploration and production (OG) and solid fuels (SF).

The aim of the THERMIE programme was the development and dissemination of new technologies across all energy sectors as an essential part of establishing a strong energy base in Europe to meet the new economic and industrial demands provided by the unified internal market, offering today the chance to the European energy industry to compete also on a globalised world market.

Activities in the field of combustion technologies and power generation are mainly covered by the SF sub-sector. These activities within THERMIE are highlighted by projects like Puertollano (IGCC), Gardanne (CFBC) or Point of Ayr (Coal Liquefaction).

As shown in Figure 5, in 1984, parallel to the demonstration of energy technologies the EC started within its framework programmes or in separate actions to support also research and development of energy technologies. One main programme in the field of research and development was the so called JOULE programme.

The JOULE (Joint Opportunities for Unconventional or Long-term Energy supply) programme was a specific programme to support RTD work in the field of non-nuclear energies and the rational use of energy. Its objectives covered the whole range of energy related technologies, i.e., rational use of energy, fossil fuels and renewable energies.

[1] 1 ECU ≅ 1.16 USD (April 1998)

Within the 4th framework programme, (see also Figure 5) all R&TD in the field of non-nuclear energy is concentrated in only one specific programme. Because this programme brings together the former RTD activity JOULE and the Demonstration activity THERMIE it is also called the JOULE-THERMIE programme. About 1000 MECU (USD 1160 M) were made available under the non-nuclear energy budget for the JOULE-THERMIE programme (for 4 years).

The objectives of JOULE-THERMIE are three-fold: to reduce the environmental impact of energy use, to improve efficiency and to carry out research into renewable energy sources and fossil fuels.

Where appropriate, there may also be international, national or regional co-operation, e.g. in order to promote energy technologies more efficiently.

Table 1 gives the approximate share of the non-nuclear energy programme across the different sectors

European programmes are on top of national programmes and industrial initiatives. The objectives of the EC programmes come out of discussions with representatives of Member States and European industry and therefore reflect very well the spectrum of technologies under development within the European Union. Especially for the demonstration programmes, the conclusion can be drawn that subjects covered by related projects give a good picture of the state of the art of technologies which are commercially available today, or at least will be available in the immediate future. Taking into account what was said about today's technological requirements of emerging economies, it becomes clear that European industry can offer commercially the whole range of technologies under discussion for these countries.

Table 1 Share of budget across the different sectors of the JOULE-THERMIE programme

Programme/Sector		JOULE RTD	%	THERMIE Demo	%	Total	%
	Mio. ECU	95		118		213	
Rational Use of Energy (RUE)			12		15		27
	USD M	110		137		247	
	Mio. ECU	220		134		354	
Renewable Energies (REN)			28		17		45
	USD M	255		155		410	
Fossil Fuels (FF)	Mio. ECU	39		181		220	
Solid Fuels			5		23		28
Hydrocarbons	USD M	45		210		255	
	Mio. ECU	354		433		787	
Total			45		55		100
	USD M	410		502		912	

Nevertheless, European industry has to face the problem of the investment costs of such installations. Advanced technologies, and even standard technologies at European (environmental) level are often rather expensive. Considerable efforts are on the way to make European technologies cost attractive both in terms of investment (ECU/kW, USD/kW) and in terms of generation costs (ECU/kWh, USD/kWh).

Recently, preparation for the next (5th) Framework Programme which will become effective during 1998 are under way. The programme is expected to consolidate research efforts, incorporate new topics and change the way in which R&D is organised. There is broad consensus between all that the next programme will contain an energy chapter. It can be expected that the financial support for coal related actions will continue in the same order of magnitude than in the recent programme.

IV STATUS OF EU CLEAN COAL TECHNOLOGIES

The increasing use made of solid fuels, which with regard to the rising world energy requirements is inevitable, requires that the use of solid fuels should take place in an environmentally acceptable way so that economy as a whole can grow in an environmentally sustainable manner. Commercially proven clean coal technologies were developed in the 80s. The successful result of this innovation is today's availability of solid fuel-based firing systems with negligible residual dust, SO_2 and NO_x emissions. These plants comply with even the most stringent national and European environmental requirements. In the last few decades, the efficiency of solid fuel-fired power plants has been stepped up to such an extent that the feedstock input has decreased from 0.550 tce[2]/MWh to 0.290 tce/MWh. In the future, less than 0.250 tce/MWh seems to become achievable.

Since the mid-70s, the EU programmes THERMIE, JOULE and ECSC have triggered major initiatives and rendered considerable assistance in respect of the development, demonstration and market introduction of technologies for clean use of solid fuels. In the future, too, RTD & Demonstration is necessary to successfully continue the developments, which have to focus on strengthening of the conversion processes' competitiveness and the increase in efficiency, i.e. the reduction in CO_2 emissions; furthermore to further the introduction of new processes into the market. Ultra-clean technologies are needed to reach the EU's CO_2 mitigation goals. RTD has shown that these technologies are feasible and can be developed in a relatively short time.

The following figures show the status of the development of some conventional and advanced solid fuel conversion technologies mentioned earlier in this paper.

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2 tce: tonnes of coal equivalent (1 tce $\cong$ 8.14 MWh $\cong$ 29.3 MJ)

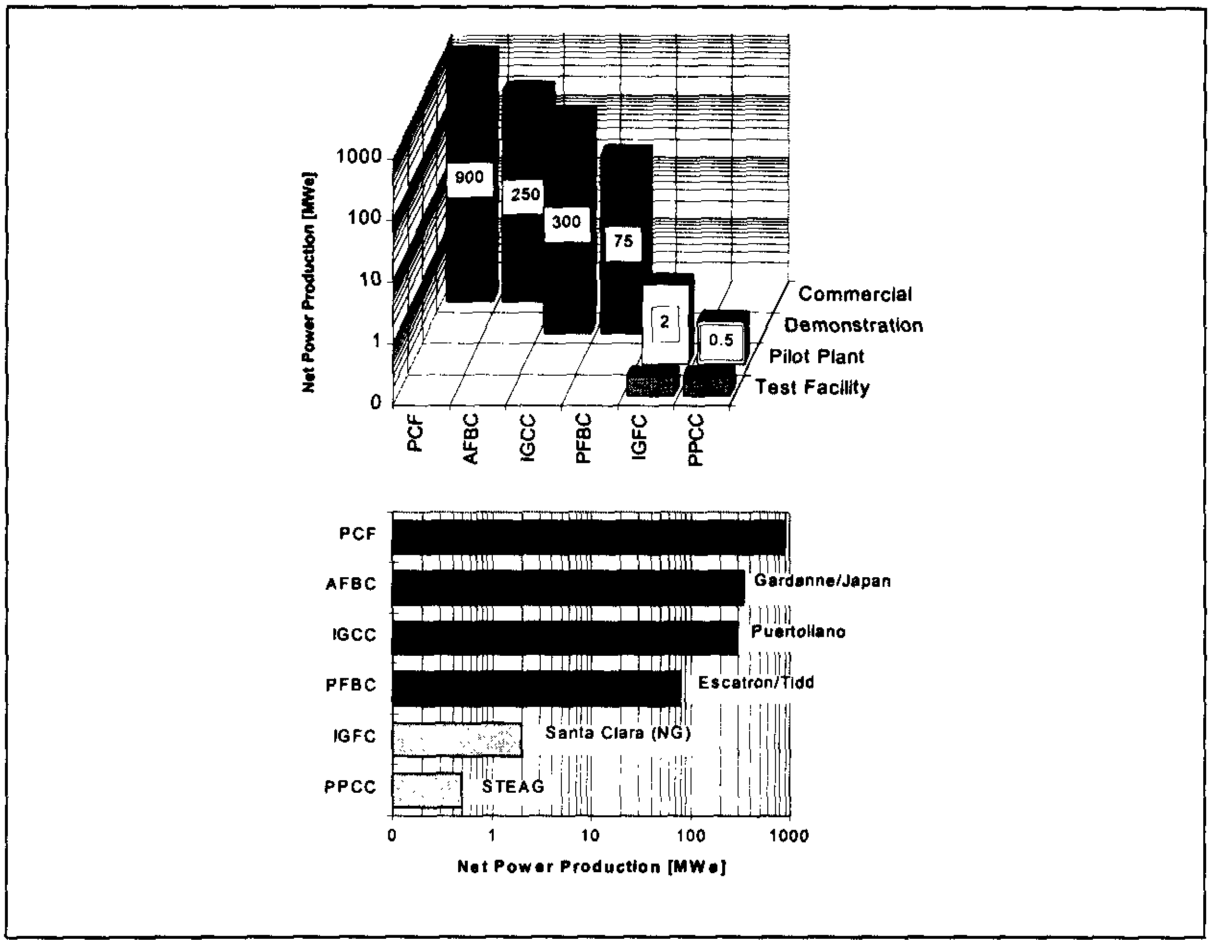

Figure 6 State of the Art of Conventional and Advanced Solid Fuel Conversion Technologies.

Figure 6 gives the recent possible unit size for the different technologies. Additionally the status of development is displayed. It can be seen out of the graph e.g. that PCF and AFBC are under commercial operation whereas IGCC and PFBC are still more in the demonstration phase. The other technologies are in an earlier stage of development and not yet ready for market introduction. Figure 6 displays additionally some specific plants (IGFC is an development phase in the EU. No specific plant was built to date). Figure 7 gives an idea about recent and expected efficiencies of SF based Power Generation.

Table 2 presents a very simplified positioning of the different clean coal technologies - introduced before - from research to market. Notes 5 to 1 correspond to the decreasing needs for efforts in the specific areas. It can be seen from this table that PCF is the technology which is most commercial followed by AFBC and PFBC. The other technologies are thought to need more RTD work to become fully commercial.

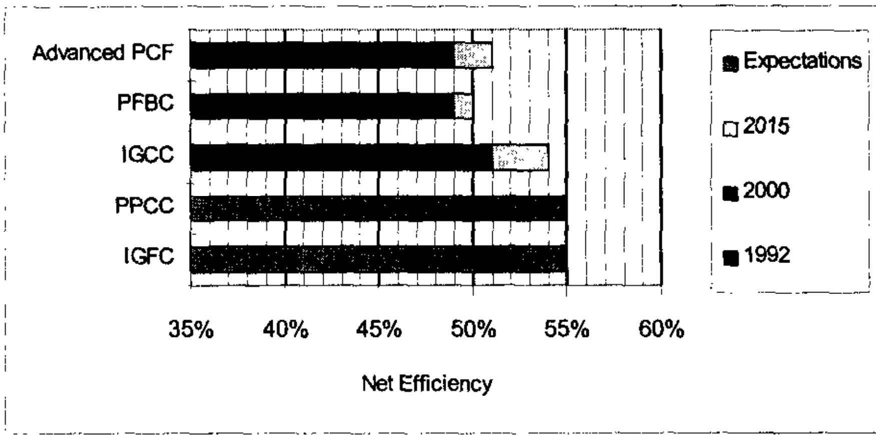

Figure 7 Net Efficiency of Solid Fuel-Based Power and Heat Generation Technologies

Even so several of the technologies already reached an advanced state of development or are already in commercial scale operation there is still a lot of RTD&D work to be done for all mentioned technologies. Table 3 summarises the focal RTD & D points described according to their chronological development order:

Research ⇔ Technical Development ⇔ Demonstration.

At all stages of technology development, cost reduction, availability and reliability are primary targets with very high priorities.

In view of the foreseeable market conditions the most important requirements to be met by advanced solid fuel conversion technologies are:

- Competitive electricity generation costs
- Environmentally compatible and efficient processes for the use of solid fuels

In view of the increasing competition in the energy market, particular importance is being attributed to industrial-scale demonstration of new processes since competitiveness is not determined by capital expenditure alone; fuel consumption, plant availability and reliability - characteristic features that can only be demonstrated by many years' plant operation - play an at least equivalent role. Only when the producers can refer to reference plants, worldwide marketing potential will exist.

Table 2 Positioning of the technology from research to market.

Sector	Technology	Basic R&D	Applied R&D	Demonstration	Commercial	Wide Replication
SF	Advanced PCF	1	3	4	5	5
	AFBC	1	2	3	3	4
	PFBC	2	3	3	4	5
	IGCC	2	4	4	3	3
	PPCC	5	5	R&D Phase	R&D Phase	R&D Phase
	IGFC	5	5	R&D Phase	R&D Phase	R&D Phase

Table 3: RTD and Demonstration Requirements of Advanced Coal Conversion Technologies

	Research	Technical Development	Demonstration
Ad-vanced PCF	♦ Advanced materials ♦ Co-combustion of low-rank feedstock ♦ *Utilisation of solid* residues	♦ Low-price emission control ♦ Steam turbine for ultra-supercritical steam cycle ♦ Drying technologies for high-moisture solid fuels (e.g. brown coal)	♦ Low-price emission control (SO_2, NO_x) ♦ Large-scale demonstration of supercritical steam cycles ♦ Ultra-supercritical steam cycle ♦ Drying technologies for high-moisture solid fuels (e.g. brown coal) ♦ Large-scale utilisation of pre-dried solid fuels
AFBC	♦ Advanced materials ♦ Predicting performance with respect to agglomeration and deposition ♦ Material wastage due to hard minerals in the bed material ♦ Co-combustion of biomass and recovered fuels ♦ Utilisation of solid residues	♦ Advanced materials testing ♦ Fuel feed and ash handling for off-design feestock to achieve the proposed fuel flexibility ♦ Optimisation of emission control, operating parameters and sorbent feed ♦ *Reducing N_2O emissions* ♦ Supercritical steam cycles	♦ Improved erosion and corrosion behaviour ♦ Fuel flexibility ♦ Co-combustion of biomass and recovered fuels on commercial scale ♦ Large-scale applications (e.g. > 250 MWe up to 500-600 MWe) ♦ Large-scale demonstration of supercritical steam cycle ♦ Ultra-supercritical steam cycles
PFBC	♦ Understanding combustion chemistry (e.g. NOx and sulphur capture) ♦ Advanced materials ♦ Components for HGCU ♦ Alkali-corrosion restricting the use of feedstock with high alkali or chlorine content ♦ Method for reducing N_2O ♦ Predicting the effects of feedstock properties on design and operation to achieve the proposed fuel	♦ HGCU ♦ Circulating PFBC concepts ♦ Second generation PFBC concepts (e.g. topping combustor) ♦ Proper feedstock preparation with respect to excess moisture and choice of sorbent to prevent e.g. post-bed combustion, plugging of the fuel feed and bed agglomeration	♦ Maintainability ♦ Circulating PFBC concepts ♦ Long-term operation costs ♦ Second generation PFBC concepts (e.g. topping combustor) ♦ Commercial-scale HGCU units ♦ Advanced gas turbines with higher inlet temperatures ♦ Fuel flexibility

	flexibility ♦ Utilisation of solid residues	♦ Efficient sorbent utilisation to prevent high amount of residues	

Table 3: RTD and Demonstration Requirements of Advanced Coal Conversion Technologies (cont)

	Research	Technical Development	Demonstration
IGCC	♦ Advanced materials for refractory lining and high temperature heat exchangers ♦ Utilisation of solid residues	♦ Improved and simplified plant design resulting into reduced capital exenditure and thus, reduced cost of electricity ♦ Thermodynamic optimisation of the water-steam cycle ♦ Reduced start-up time ♦ Utilisation of solid residues ♦ HGCU with respect to dry dust removal and fuel gas desulphurisation ♦ Enhanced fuel preparation and solids handling ♦ Gasification processes for different applications	♦ Gasification processes for different feedstock incl. co-gasification of low-rank feedstock, biomass and recovered fuels ♦ Enhanced fuel preparation and solids handling (e.g. pre-drying of high-moisture feedstock, slurry preparation) ♦ Commercial-scale HGCU ♦ Advanced gas turbines for low- and medium-BTU fuel gas ♦ Reduced start-up time ♦ Utilisation of solid residues
PPCC	♦ Detailed understanding of various mechanisms related to pressurised combustion (e.g. chemistry, particle behaviour, mass and heat transfer) ♦ Retention of vapour phase alkali species ♦ Material wastage (e.g. erosion and corrosion) of components exposed to high-temperature corrosive environment ♦ Combustion, slagging and corrosion behaviour of various types of feedstock ♦ Advanced high-temperature heat exchangers	♦ Sufficient removal of molten fly ash ♦ On-line measurement devices detecting particulates and alkali species ♦ Advanced high-temperature heat exchangers ♦ Feasibility studies	♦ After completion of the technical development
IGFC	♦ Development of advanced materials (metals and ceramics) in order to increase stack lifetime and durability	♦ Development of low-cost components and cost-effective manufacturing processes	♦ After completion of the technical development

	♦ Low-cost materials ♦ Stack design meeting internal requirements like electrical contact and sealing and external requirements like pressure and thermal expansion ♦ Thin layer technology	♦ Thin layer technology ♦ Reduced system complexity ♦ Pilot-scale test facilities under real gas conditions ♦ Feasibility studies	

At present, only a few projects of ultra-clean coal technologies are under way. The main barriers are the high risks and costs connected with industrial-scale demonstration, the increasing price competition in the energy markets and the long development periods for new technologies. European pre-competitive support programmes can provide the industry with appreciable momentum and speed up the advanced technologies' development by cost and risk sharing.

The development and demonstration activities for advanced solid fuel conversion will have to cover a broad spectrum of technologies. The comparison shows that no single conversion technology performs best within all valid criteria, as there are: Cost, maturity of technology, environmental requirements and thermal efficiency at full load and partial loads, plant size, fuel flexibility, operative performance (e.g. during load variation, at minimum load, simplicity of operation), availability, reliability, maintainability and construction issues. In view of this variety of technological approaches it is concluded that financial incentives will be needed to increase the uptake rate of advanced technologies by the industry.

More details about the different technologies and their RTD&D needs are given in the Annex.

Power generation represents one of the bigger shares within the total energy demand with especially in emerging countries comparatively high rates of increase.

It is clear that the main market for new power plants and for retrofitting of old units will not be Europe or the OECD countries but the emerging economies outside the OECD. In the order of time expected to become effective these are the Asia-Pacific region (China, India etc.), Latin America and Africa.

The technology with the lowest electricity production costs to date is clearly the gas fired power station. This is due to the relatively low investment costs by comparatively high fuel costs. However gas has the same disadvantages as oil. The regional distribution of reserves is limited to few areas whereas coal reserves are spread more widely over the world. Therefore it seems clear that emerging countries will often rely on coal as an indigenous fuel instead of gas, even accepting slightly higher investment costs, but being able to use domestic fuels, saving foreign exchange and giving employment to their own capital. This is especially true for countries such as China and India which have reasonable reserves of coal, and which represent large markets at an already advanced stage.

Sub-critical pulverised fuel (PF) plants are expected to be the preferred technology in the short term perspective. For special purposes, fluidised bed combustion will also be taken into consideration in a few cases, e.g., to burn difficult fuels. It is unlikely that technologies such as IGCC, or even super or ultrasuper-critical plants will enter the market in the short term. Even though they provide higher environmental performance, lower maturity of the technology combined with higher investment costs create a strong barrier. Only single demonstration units can be expected for those technologies without immediate dissemination potential.

Even so, in the short term a major part of the market will be directed to more conventional technologies, the expansion in coal production and use, combined with the need to meet efficiency and environmental demands, is creating a substantial market for 'clean coal technologies' on the mid- and long-term perspective. Basically these are technologies that enhance the efficiency and environmental acceptability of coal extraction, preparation and use. They range from low NO_x burners to complex hybrid combined cycle power plant, and from new methods of mining coal to its use in advanced conventional power plant.

European Industry can provide all energy technologies requested by emerging economies without needing further research and development. Mature technologies with an acceptable environmental standard are state of the art. More advanced technologies which need further development and demonstration are not demanded by those markets to date and will probably be in place early enough to meet the future demand of the developing markets. The main question will be how to come into these markets. A major barrier can be identified with the necessary investment costs. Here is a clear field for industry to make efforts to reduce costs to an acceptable level without compromising to much on the environmental options. In parallel to these technological efforts financing models have to be developed to enable customers out of those countries to afford advanced technologies with.

V INTERNATIONAL CO-OPERATION

As mentioned above there is still a lot of RTD including demonstration work to be done for all conventional and advanced solid fuel conversion technologies. To reach the very demanding goal of climate gas reduction international co-operation and collaboration is absolutely necessary. In the framework of the OECD/IEA some common work and initiatives are already underway.

As markets become more competitive and government funding is decreasing, industry and governments are devoting fewer resources to technology development. Under these conditions co-operation and collaboration on technology research and development will prove beneficial to the parties involved as it will accelerate energy technology development at a reduced cost.

The EU is ready to collaborate with other countries and especially with the USA and Japan, not only for the smooth technology transfer of Clean Coal technologies to the emerging and developing countries but also to collaborate in assisting these countries to create supporting infrastructures for advanced technologies in the areas of operation, maintenance and management.

The more general level of co-operation within the IEA should be backed by bilateral co-operation e.g. between related institutions and/or industrial organisations of USA and the EU. International Co-operation including industry participation should be encouraged. The following action-list could be a basis for initiating common actions.

1. Identify and define areas of common interest where collaboration seems of advantage for all parties (Adoption of legal framework for co-operation, Public guaranties for investments, Workshops on different levels (governmental or industrial) for defining common work-programmes)

2. Intensify collaboration on a personal level (e.g. to bring together technical and administrative managers from different countries in order to identify areas of collaboration on technology development areas, organised and financed jointly by different partners)

(Business missions, site visits, visits of research and industrial installations, workshops, exchange of technical and administrative staff in both directions to increase the mutual understanding)

3. Concrete Projects
   (Feasibility (market) studies, common (demonstration) projects, (e.g. combining technologies of different partners for the sake of the customers and the environment), common research projects with intensive exchange of staff and results, repowering projects

4. Dissemination activities
   (Exhibitions, publication, training of scientific, technical and administrative staff, workshops)

An other aspect to intensify International Co-operation is that this can help to maintain a competitive market and to avoid a competition of funding which at the end only benefits third parties.

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VII ANNEX 1: ADVANCED SOLID FUEL CONVERSION TECHNOLOGIES

Advanced pulverised coal-fired boilers (PCF)

Technology Description

Pulverised Coal-Fired (PCF) boilers have been in use since the early 1900s and are currently the most widely accepted technology (especially for cost reason) for large-scale coal-fired heat and electricity generation.

Most of the conventional PCF boiler systems currently in operation use subcritical pressure (< 221.2 bar) steam cycles with superheated and single reheated steam. This results - depending on feedstock, steam conditions, condensing pressure and plant size - in net thermal efficiencies in the range of 35 - 38 %.

A smaller number of units already operate with supercritical[3] steam cycles (steam pressure some point above 221.2 bar, single reheat and main steam and reheat steam temperature around 540 °C) which - together with some other means of thermodynamic optimisation and an increase of plant capacity - rise the net efficiency to up to 44[4] %.

Even higher efficiencies up to some 50 % can be obtained by further raising steam parameters to the so-called „ultra-supercritical“[8] conditions (maximum steam pressure above 248 bar and maximum steam temperature above 566 °C).

Today, concepts are underway to further improve the efficiency of PFC power plant technologies based on high-moisture low-rank solid fuels (e.g. brown coal) by applying external drying processes.

In addition to the thermodynamic improvements, optimised low-price primary or secondary emission control technologies for SO_2 (e.g. less space requirements, regenerative sorbents) and NO_x (e.g. furnace modifications, LNB, fuel staging) have to be developed and realised in order to strengthen the near future economic competitiveness of advanced PFC.

Development Needs

According to the above-mentioned targets advanced PFC systems require the following developments:

- Advanced high-temperature corrosion and erosion resistant materials for „ultra-supercitical“ steam cycles
- Advanced steam turbines for „ultra-supercitical“ steam cycles
- Commercial large-scale demonstration of supercritical steam cycles up to 1,000 MW_e
- Low-price primary or secondary emission control (e.g. SO_2, NO_x)

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3 Supercritical and ultra-supercritical steam cycles are of general importance and could also be applied to other advanced solid fuel-based conversion technologies mentioned in this chapter.

4 Denmark: hard coal-fired power plants - coastal sites with access to cold seawater

Résumé

Advanced PFC units with high steam conditions (supercritical water-steam cycle) are available and will demonstrate their technical and economic competitiveness in the near future. Further progress in respect of „ultra-supercritical" steam conditions and thermodynamic optimisation are feasible. Depending on the RTD results obtained for advanced materials, such developments could become available for demonstration and probably for commercial application during the next decade.

Atmospheric fluidised-bed combustion (AFBC)

Technology Description

The atmospheric fluidised-bed combustion (AFBC) technology consists of forming a bed of finely sized ash, limestone (for sulphur removal), and solid fuel particles in a furnace and forcing combustion air up through the mixture, causing it to become suspended or fluidised.

The atmospheric „bubbling-bed" AFBC technology (BFBC) has a defined height of bed material and operates *at or near atmospheric pressure in the furnace. In the mid-1970s, the atmospheric „circulating" fluidised-bed* combustion technology (CFBC) was developed. CFBC has particular advantages, e.g. with respect to heat transfer, combustion efficiency and fuel feed.

AFBC can control gaseous emissions already during combustion by addition of limestone or dolomite (SO_2) and through low combustion temperatures and staged combustion (NO_x). AFBC is a very suitable conversion technology for a large variety of biomasses and recovered fuels.

AFBC units have commercially been available for about ten years, and there are some 550 units installed world-wide. AFBC concepts with capacities of up to 200 to 400 MW_t are considered to be a commercial technology for utility and industrial applications. The 250 MW_e CFBC unit at the Provence Power Station, Gardanne, France, was sponsored by EU's THERMIE programme and is the largest unit in operation. CFBC units of up to about 400 MW_e are now being offered with full commercial guarantees.

Development Needs

In order to make the AFBC technology even more competitive, the following issues require further development:

- Fuel feed and ash handling for off-design feedstock to achieve the proposed fuel flexibility
- Predicting performance with respect to agglomeration and deposition
- Material wastage due to hard minerals in the bed material
- Advanced materials (e.g. refractory materials)
- Optimisation of emission control, operating parameters and sorbent feed
- Reducing NO_x and N_2O emissions by low-price control devices
- Utilisation of solid residues (bed material and fly ash)
- Co-combustion of biomass and recovered fuels on a commercial scale
- Improvement in design in order to reduce costs
- Large-scale applications (e.g. > 250 MW_e up to 500 - 600 MW_e)
- Supercritical and ultra-supercritical steam cycles

Résumé

The AFBC technology is expected to continue to play an important role in the intermediate market - especially for low-rank fuels - with capacity demands of up to 500 MW_t. However, large-scale applications of the AFBC technology have to demonstrated.

In the field of AFBC, further RTD and demonstration are necessary to make this technology less expensive and more reliable. Other major RTD and demonstration topics will cover co-combustion of biomass and recovered fuels, fuel flexibility, utilisation of solid residues, emissions and emission control resulting in an increased availability and, thus, in more economic competitiveness.

In addition to short-term off-site research, most of the individual research topics may well be investigated and demonstrated using existing AFBC units. Improvements achieved may directly be incorporated into the next generation of commercial-scale plants and thus be demonstrated within the next 5 to 10 years.

Pressurised fluidised-bed combustion (PFBC)

Technology Description

A PFBC system operates a fluidised bed at an elevated pressure level. Because of the higher pressure, the exhaust gases from PFBC have sufficient energy to drive a gas turbine while the steam generated in the in-bed boiler tubes drives a steam turbine. This combined cycle configuration allows net efficiencies in excess of 40 to 45 %.

Similar to AFBC, PFBC can control gaseous emissions already during combustion by addition of limestone or dolomite ($_{SO_2}$) and through low combustion temperatures and staged combustion (NO_x). Since high-temperature particulate removal systems were not available for recent concepts, only cyclones have been used for a coarse particulate removal upstream of the gas turbine so far. Thus, the gas turbine's expander is operated with dust loaden flue gas. An electrostatic precipitator or bag filter is required downstream of the economiser to remove the remainder of the fly ash.

The development of PFBC has been underway since 1969. Today, the PFBC technology is in the early stages of commercialisation. Five PFBC units of less than 80 MW_e, two in Sweden (Värtan), one in Spain (Escatrón), one in the United States (Tidd) and one in Japan (Wakamatsu) have been put into operation. The Escatrón project was sponsored under the EU THERMIE programme.

Similar to AFBC, bubbling fluidised bed (PBFBC) and cirulating fluidised bed (PCFBC) concepts are unter development with several advantages for the PCFBC design (e.g. fuel distribution, heat exchange, staged combustion).

This state-of-the-art can be regarded as the „first generation" PFBC technology. The „second generation" PFBC technology may utilise a topping combustor to increase the inlet temperature to the gas turbine. In this case, a device for high-temperature high-pressure particulate removal (HGCU) has to be installed between the fluidised-bed combustor and topping combustor to remove virtually all of the ash upstream of the topping combustor. Due to the high gas turbine inlet temperature significant additional cycle efficiency can by achieved resulting in a net thermal efficiency of some 50 %.

In terms of operational behaviour and primary emission control, circulating PFBC technology may have advantages over bubbling PFBC technology.

Development Needs

With respect to the first generation PFBC technology, the following issues still require further RTD and demonstration:

- Gas turbine operation in a „high-dust" corrosive environment
- Improvements in the overall reliability, availability and maintainability
- Circulating PFBC concepts
- Improved and simplified plant design resulting in reduced capital expenditure and thus, reduced cost of electricity
- Predicting the effect of feedstock properties on design and operation to achieve the proposed fuel flexibility
- Proper feedstock preparation with respect to excess moisture (e.g. slurry feed) and choice of sorbent to prevent post-bed combustion, plugging of the fuel feed and ash removal, bed agglomeration and sintering
- Corrosion due to volatile alkali species restricting the use of feedstock with high alkali metal or high chlorine content
- Alkali control
- Efficient sorbent utilisation to prevent a high amount of residues
- Utilisation of solid residues and by-products
- Method for reducing N_2O emissions
- Understanding of the combustion chemistry (e.g. NO_x and sulphur capture)
- Scale-up to larger sizes of about 600 MW_e

With respect to the second generation PFBC technology, the following issues require further development:

- Topping combustor technology
- Efficient high-temperature (800 - 900 °C) particulates removal systems
- Advanced gas turbine technology for high-temperature flue gas

Résumé

The PFBC technology is under demonstration today. Even though the demonstration phase has already started, further RTD and demonstration work is necessary to improve particular components and operational performance of the first generation PFBC systems (e.g. gas turbine operation in a high dust environment, improved and simplified plant design resulting in reduced capital expenditure, proper feedstock preparation, emission related issues).

Improvements achieved from this research may directly be incorporated into the second generation PFBC technology, which is under development today and thus to be demonstrated on a commercial scale within the next 5 to 10 years.

As soon as sufficient progress in the combustor technology (e.g. circulating PFBC), HGCU and advanced gas turbines has been made, demonstration projects are appropriate to verify the significant potentials of the second generation PFBC technology.

Integrated gasification combined-cycle systems (IGCC)

Technology Description

The IGCC-based electricity generation combines two technologies: (a) Gasification of solid fuels and (b) combined-cycle electricity generation based on highly efficient combustion gas turbines combined with a conventional water-steam-cycle. The clean-up of the fuel gas derived from gasification of solid fuels is of major importance to the IGCC technology.

Several pre-commercial IGCC projects are in operation or under construction in the United States (Wabash River 262 MW_e, Polk Power Station 250 MWe, Piñon Pine 99 MW_e) and Europe (Buggenum 253 MWe, Puertollano 335 MWe). The net efficiency of these pre-commercial IGCC projects ranges between some 41 and 45 %. However, these values have still to be demonstrated.

Today, a large variety of different IGCC concepts are under consideration. Their particular features refer to the gasification process being incorporated (e.g. Shell, Prenflo, Lurgi-BGL, HTW or others), to the gasification agent being applied (oxygen plus steam or air), to the degree of feedstock utilisation in the gasifier (e.g. Air Blown Gasification Cycle ABGC[5] providing partial gasification), to the fuel gas clean-up concept and to the incorporation of the gas turbine.

The future advances in gasification-based electricity generation, however, are linked to increases in gas turbine firing temperature, hot gas clean-up of the fuel gas, co-production of both chemicals and electricity and improved gasifier designs. It is expected that net efficiencies may well exceed 50 % if such developments can be successfully linked with or integrated into IGCC power plant technology.

Development Needs

With respect to the IGCC technology, especially the following issues require further development:

- Improved and simplified plant design resulting in reduced capital expenditure and thus, reduced cost of electricity
- Improvements in the overall reliability, availability (e.g. shorter start-up procedures) and maintainability
- Gasification processes for different feedstock including co-gasification of low-rank feedstock, biomass and recovered fuels
- Enhanced feedstock preparation and solids handling (e.g. pre-drying of high-moisture feedstock and slurry preparation)
- Advanced materials for refractory lining and high-temperature heat exchangers
- HGCU with respect to dry dust removal and fuel gas desulphurisation
- Advanced gas turbines for low and medium BTU solid fuel-derived fuel gas
- Thermodynamic optimisation of the water-steam cycle
- Utilisation of solid residues (for some of the above-mentioned gasification processes)
- Scale-up to larger sizes of > 600 MW_e (utility use)

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[5] ABGC: 80 % of the feedstock is converted into a fuel gas and the remaining 20 % of char is fed to a CFBC

Résumé

The IGCC power plant technology is under demonstration today and could be commercialised in the next 10 years. Major development needs cover topics like (a) sufficient reliability and availability, (b) process simplifications in order to reduce capital expenditure, (c) efficient fuel gas cleanup, (d) advanced gas turbine technology and (e) utilisation of solid residues.

Thus, further RTD and demonstration are necessary to improve components, operational performance and economic competitiveness. As a consequence, short-term off-site research and on-site investigations are necessary to verify the technical and economic potentials of the above research topics.

Improvements achieved from RTD and demonstration (e.g. economic optimisation in respect of newly developed and improved components) may directly be incorporated into the next generation of IGCC power plants, which could be demonstrated on a commercial scale within the next 5 to 10 years.

Pressurised pulverised coal combustion (PPCC)

Technology Description

The pressurised pulverised coal combustion technology (PPCC) refers to the directly coal-fired gas turbine principle. Pulverised coal is combusted at elevated pressures (> 20 bar) providing a high-temperature flue gas well above the ash melting point. Depending on the feedstock the adequate flue gas temperature level may well exceed 1,400 to 1,500 °C. „Ultra-high-temperature" gas clean-up systems are located downstream of the pressurised combustor in order to capture volatile alkali species and molten ash prior to the gas turbine. Flue gas desulphurisation is needed downstream of the WHSG in order to meet the environmental requirements. Due to the high combustion temperatures, provision has to be made for a sufficient NOx removal.

Based on today's gas turbine technology, PPCC may achieve a net efficiency of some 50 %. However, efficiency could be raised by applying future developments in the gas turbine field.

In addition to the above directly fired gas turbine principle several indirectly fired cycles (IFC) are presently investigated. These IFC call for the development of an advanced high-temperature ceramic heat exchanger to transfer the heat from the combustion section to a pressurised air stream that is the working fluid of a gas turbine. Thus, the gas turbine is not directly exposed to corrosive and abrasive combustion products. The ceramic heat exchanger tube will heat clean filtered air from the gas turbine compressor to high gas turbine inlet temperatures. The IFC principle is verified e.g. in the „Externally Fired Combined Cycle" (EFCC) or in the „High-Performance Power System" (HIPPS).

Major components of the PPCC technology have already been investigated on a pilot scale with a thermal capacity of some 0.5 to 1 MWt.

Development Needs

The PPCC technology still requires research and development in the following fields:

- Detailed understanding of various mechanisms related to pressurised combustion (e.g. chemistry, particle behaviour, mass and heat transfer)
- Retention of vapour phase alkali species
- Sufficient removal of molten fly ash

- On-line measurement devices detecting particulates and alkali species
- Material wastage (e.g. erosion and corrosion) of components exposed to the high-temperature corrosive environment
- Combustion, slagging and corrosion behaviour of various types of feedstock
- High-temperature ceramic heat exchangers

Résumé

The PPFF technology is still in an early stage of development and several years away from market introduction. Fundamental RTD efforts are needed in many fields in order to provide more detailed understanding of technical solutions for various key components.

Recent and near future RTD efforts will cover an additional time period of about 5 years. It can be expected that pilot-scale projects will not be launched before the year 2000.

Integrated gasification fuel cell systems (IGFC)

Technology Description

Fuel cells are of interest because of their potential for high energy conversion efficiency. Fuel cells convert fuel gas containing hydrogen and carbon monoxide directly into direct current. A fuel cell conversion system essentially consists of four fundamental parts: (a) Coal gasification process, (b) fuel cell stacks converting hydrogen and carbon monoxide into electricity (DC), (c) conditioning system converting DC power into high voltage alternating current (AC) and (d) heat recovery system producing steam and improving the overall conversion efficiency of the fuel gas into electricity.

Since fuel cells convert chemical energy directly into electric energy, the conversion efficiency is not affected by Carnot cycle limitations. Fuel cells operating at high temperatures (650 - 1,000°C) can be coupled to a steam bottoming cycle to provide a fuel cell combined cycle power system with conversion efficiencies of 50 percent to 60 percent (LHV).

Presently, the phosphoric acid (PAFC) systems are the most technically mature of the three classes being developed. PAFC systems converting natural gas are commercially available in sizes from 50 to 200 kWe to as much as 11 MW_e. Today, molten carbonate (MCFC) is emerging from laboratory-scale testing to 100 kW_e pilot plants. The first full-scale 2 MWe demonstration plant is sited at the city of Santa Clara, California, and started operation using natural gas in early 1996. The solid oxide (SOFC) technology is the least developed of the three alternatives. Tests have been conducted with stacks in the range of 10 to 100 kW_e, depending on type and vendor.

While the first generation will be fuelled by natural gas, future applications can be based on coal-derived fuel. Thus, the IGFC technology offers an additional opportunity to use solid fuels with high thermal efficiency and good environmental performance.

Development Needs

The three primary issues associated with the fuel cell technology are:

- Development of cost-effective manufacturing processes

- Stack lifetime and durability (e.g. by developing advanced materials)
- Reduced system complexity and increased reliability
- Appropriate fuel gas production (e.g. gasification) and processing systems (HGCU)

Résumé

From today's point of view, the IGFC systems based on MCFC and SOFC and operating on coal-derived fuel gas will not enter the demonstration phase in the next 10 years. However, continued research on component development for both MCFC and SOFC is useful as these electricity generating systems, coupled to gasification processes, promise very high efficiency and clean electricity from solid fuels.

The future development of solid fuel-based IGFC systems will depend on the success of the current natural gas-based technology development and on the resolution of key technical issues. As soon as reasonably sized modules (e.g. 1 - 2 MWe) are commercially available, the focus should be on continued integrated testing of fuel cells with coal-derived fuel gas.

Today, it is hard to predict whether already in the 10 years' period considered the industrial-scale demonstration on the basis of coal-derived fuel gas can be taken into account as well. For this reason, the development activities in the next few years should be carefully pursued.

Magnetohydrodynamic electricity generation (MHD)

Technology Description

Magnetohydrodynamics (MHD) is a direct plasma energy conversion technology for electricity generation. MHD can be achieved by burning coal in a pressurised combustor with preheated air or oxygen to produce a combustion gas having a temperature between 2,300 and 2,800 °C. A seed material, such as a potassium salt, is added to increase electric conductivity. The combustion gas and vaporised or ionised seed are passed through a MHD channel within the centre bore of a superconducting magnet. This interaction produces direct current electricity in accordance with the Faraday principle. The remaining heat is used to make steam to drive a conventional turbine generator.

In the past, MHD electricity generation was investigated in different projects performed in the United States, Russia and Israel in order to prove the basic concept of this technology.

Development Needs

With respect to MHD technology the following issues require further development:

- Long-term high-temperature component durability
- Design and development of a high-temperature heat exchanger
- Low-cost seed recovery
- Design and operation of a complete MHD electricity generating system on a sub-scale
- Scale-up features

Résumé

Relative to other advanced solid fuel conversion technologies now under development, MHD systems pose much greater technological challenges because of the aggressive thermal environment and the system complexity. At the same time, there seems to be no further advantage in thermal efficiency due to the recent progress of the other solid fuel-based technologies e.g. advanced gas turbines, fuel cell and gasification processes. From this it can be concluded that there are no demonstration needs in the field of MHD technology. Thus, MHD is not taken into account in any of the evaluations.

VIII ANNEX 2: KEY COMPONENTS AND MULTI-PURPOSE TECHNOLOGIES

Drying processes for low-rank coals, biomass and residues

Technology Description

Low-rank coals (e.g. lignite, brown coal), peat, biomass (e.g. wood, straw or pulp) and recovered fuels (e.g. wastes, waste plastic materials, sewage sludge) may contain a significant amount of moisture.

In order to utilise such materials as a feedstock or co-feedstock for heat and electricity generation, dewatering or drying is often necessary to achieve appropriate bulk material properties. In addition to this, dewatering or drying are beneficial to various heat and electricity generation processes in order to provide maximum conversion efficiency.

Both, internal and external drying of the feedstock is possible. Internal drying - during combustion or gasification itself - requires a lot of sensible heat. Thus, heat and electricity generation processes with internal drying have significant thermal losses and a reduced net thermal efficiency.

If an efficient external drying step (e.g. including waste heat utilisation) is applied during feedstock preparation, the net efficiency of the entire electricity generation process will increase by up to 5 % points.

Intensive efforts are underway world-wide to develop efficient external drying technologies. Among the approaches feasible for commercial application, technologies based on fluidised-bed drying have already achieved significant progress. The moisture extracted from the feedstock is either condensed for preheating purposes or recompressed and condensed to act as the heating medium according to the heat pump principle. The condensate may well be used as feedwater for several consumers in the downstream electricity generation process and thus reduce the overall water consumption.

Today, fully equipped pre-commercial fluidised-bed drying units with water evaporation capacities of some 20 to 30 t/h are in operation in brown coal upgrading facilities in Loy-Yang (Australia) and Frechen (Germany). The fluidised-bed drying unit located at Frechen already includes facilities for vapour recompression providing a complete internal waste heat utilisation to the drying process.

Development Needs

With respect to drying processes for low-rank coals, biomass and residues, the following developments are necessary:

- Design and operation of appropriate drying processes for several different feedstocks
- Implementation of waste heat recovery systems (e.g. vapour recompression)
- Treatment (e.g. clean-up) of the condensed water vapour
- Appropriate feedstock preparation for particular drying processes
- Solids handling (e.g. transportation, storage, feeding systems)
- Integration of commercial-scale drying processes into advanced solid fuel-based electricity generation systems

Résumé

Today, various drying technologies are available on a pre-commercial scale. Prior to commercial application further RTD and demonstration work is necessary to adapt these technologies to the particular features of various low-rank and high-moisture types of feedstock and to integrate the drying technology into processes for heat and electricity generation.

From today's point of view, appropriate technologies will be available in a time period of 5 to 10 years from now before being linked to advanced solid fuel-based electricity generation systems.

Co-utilisation of coal, biomass and recovered fuels

Blending biomass and recovered fuels (e.g. municipal, agricultural, foresty or industrial waste) with coal as a feedstock for new generations of power plants provides an innovative means of tackling greenhouse gas emission problems. Recovered fuels from various waste materials are useful and CO_2-neutral feedstock and also offer an ingenious way of reducing or solving accumulating waste disposal problems.

As soon as biomass or recovered fuels can be introduced to advanced solid fuel conversion processes without altering electricity output and emissions, co-utilisation of such feedstock would have the following benefits:

- Electricity and heat generation with almost zero additional emissions of CO_2
- Electricity and heat generation with almost zero additional pollutants
- Preservation of valuable reserves

From the economical point of view, however, co-utilisation has to implemented without additional costs in order to be a potential alternative to conventional electricity generation.

Performed from 1992 to 1994, the European Commission's „APAS Clean Coal Technology" programme was the world's largest RTD effort in the area of co-combustion and co-gasification of coal, biomass and recovered fuels. This project involved a large number of participants from European industrial companies, European universities and European research centres. Co-utilisation was investigated from small laboratory-scale rigs (10 kW) to large-scale (150 MW_e) units. The programme has proved that co-utilisation of biomass and various waste materials blended with coal is technically feasible, economically attractive and environmentally beneficial with minor optimisations and adaptations of both existing and advanced technologies.

Even though recent RTD has made significant progress in the field of co-utilisation of coal, biomass and recovered fuels, further work is needed prior to more global application:

- Feedstock preparation and feeding systems (optimisation)

- Fuel characterisation (screening tests for different biomasses in various systems)
- Corrosion (detailed investigations and long-term testing)
- Sintering and slagging (detailed investigations and long-term testing)
- Utilisation of residues from co-gasification and from co-combustion in AFBC plants
- Process optimisation (e.g. HGCU, gas turbine, integration of advanced technologies)

Low-cost combined heat and power generation (CHP)

Combined heat and power generation (CHP) is a very important option to increase energy efficiency. Even though the possibilities of preserving fossil fuel reserves by installing CHP plants are often overestimated, there are still reasonable scenarios where CHP technologies should be applied from the viewpoint of technical and economical feasibility. The remaining potentials for applying CHP technologies probably involve many small-scale to medium-scale CHP plants.

In terms of conversion efficiency and electricity generation costs, electricity production in small-scale to medium-scale CHP plants is less effective and disproportionately more expensive than electricity generation in central large-scale coal-fired power plants using state-of-the-art electricity generation technology. Thus, the overall profitability of CHP plants is highly dependent on capital expenditure and operating costs and on the local situation concerning the heat market.

RTD and demonstration in the field of combined heat and electricity generation should therefore focus on the following aspects:

- Development of low-price cost effective technologies for small-scale to medim-scale electricity generation
- Co-utilisation of coal and locally available biomass or recovered fuels

HGCU for solid fuel-based combined-cycle electricity generation

Technology Description

Advanced solid fuel-based electricity generation systems which are linked to gas turbine technology (PFBC, IGCC, IGCF, PPCC) could be improved with respect to thermal efficiency if solid and gaseous pollutants are removed at high temperature and high pressure. Thus, the gas turbine requirements and the emission standards can be met without any further gas clean-up upstream of the stack.

Gas clean-up at elevated temperature refers to the so called „Hot Gas Clean-Up“ (HGCU) technology. The introduction of HGCU offers the potential for a lower cost approach to pollutant control with associated cycle efficiency advantages.

Development Needs

HGCU has achieved different levels of development for different types of applications. However, RTD as well as demonstration projects are still required in the following fields:

- Removal of sulphides, ammonia, cyanides and halides for IGCC and IGFC applied in pilot-scale and demonstration projects

- Particulate and alkali vapour removal for IGCC and IGFC at temperatures of up to 900 °C in the fundamental RTD field
- Particulate and alkali removal for PFBC at temperatures in the range of 800 - 900 °C
- Development of particulate and alkali removal for PPCC at temperatures of > 1,200 °C in RTD projects
- Study of particulate filtration characteristics
- Compact design approaches
- Long-term lifetime materials
- Design features (e.g. failsafe systems, flow distribution)

In order to realise the economic and environmental advantages of PPCC, it is essential that the key components - which still have to be developed - allow not only to ensure efficient removal of the respective pollutants, but also guarantee the reliability and availability to compete with the respective conventional gas clean-up system.

Résumé

HGCU has reached different development stages for different types of applications. For example, medium temperature particulate removal for IGCC-based electricity generation is in the demonstration phase. Other HGCU applications are still at the RTD level.

Due to its importance as a key component and multi-purpose technology for various applications a lot of organisations have launched intensive RTD programmes with respect to HGCU in the recent past. It can be expected that several applications will become ready for pilot-scale or demonstration-scale projects in the near future.

Gas turbine development for coal-derived fuel gas

Technology Description

In combination with an efficient water-steam-cycle, the gas turbine will likely be a key component for several advanced solid fuel-based electricity generation systems (IGCC, PFBC, IGFC, PPCC) in the short or medium run (through 2020). Because of the very high inlet temperature level of some (850[6]) 1,000 - 1,200 °C, gas turbines have fundamental thermodynamic advantages compared with steam turbines operating at inlet temperatures in the range of 540 - 600 °C.

In the foreseeable future, the gas turbine capacity is expected to be in the range of 300 to 400 MW_e. The inlet temperature will exceed 1,200 °C. Furthermore, staged combustion is expected to raise thermal efficiency as well.

Today's commercially available gas turbines have primarily been developed for high-BTU fuels like natural gas or diesel fuel. In order to maintain their advantages for advanced solid fuel-based electricity generation technologies gas turbines must be adaptable to coal-derived fuel gas or flue gas-based operation. Fuel gas obtained from gasification of solid fuels has a much lower heating value (LHV = 4 - 11 MJ/m^3STP) compared e.g. to natural gas (LHV = 32 - 38 MJ/m^3STP). Initial efforts in this field have already been started.

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[6] Hot gas stream from PFBC

Development Needs

Development in gas turbine technology first of all covers the following fields:

- Adaptability to solid fuel-derived low- and medium-BTU fuel gases and flue gas by modified combustion systems (e.g. pre-mixing burners for high hydrogen containing fuel gas, staged combustion)
- Advanced (corrosion resistant) materials (e.g. alloys, ceramics and coating) for high-temperature applications
- Ultra-low emission combustion systems (e.g. NO_x)

Résumé

The gas turbine technology is already available in commercial large-scale units. The technology - which was in the past developed primarily for natural gas or diesel fuel - has to be adapted to low- and medium-BTU solid fuel-derived fuel gases (e.g. IGCC, IGFC) and to high-temperature high-pressure flue gas (e.g. PFBC, PPCC).

The IGCC and PFBC projects underway today will provide reasonable information in the very near future. In order to verify the benefits from the gas turbine development for applications in advanced solid fuel-based electricity generation technologies, further efforts have to be made with respect to solid fuel-related issues.

Fundamental RTD covering e.g. materials and combustion chemistry can more or less be conducted off-site and will be available in the next 3 to 5 years. Based on this experience commercial-scale advanced gas turbines fueled with coal-derived fuel gas could be available in 5 to 10 years from now on.

Advanced control systems

Technology Description

Maintaining of the major advances (e.g. thermal efficiency, low emissions, feedstock consumption and utility consumption) of advanced solid fuel conversion technologies for any kind of operation (e.g load following, partial-load, start-up, changes in feedstock properties) is a significant challenge in terms of process control.

Conventional process control systems are probably not able to accept this challenge without compromises (e.g. capital expenditure and staff). Thus, advanced control systems are needed to provide flexible, optimum and reliable operation at a low cost level which finally results in

- increased availability and in
- increased overall profitability.

One possible approach could be for example the so-called „fuzzy control" technology. Applying this technology means transforming specific knowledge of the particular process behaviour into a software code instead of defining a set of rather complex control circuits.

Development Needs

In the field of advanced control systems the following developments are necessary:

- Application of advanced control systems to various kinds of advanced solid fuel-based electricity generation technologies
- Transformation of specific knowledge into computer-aided control principles
- Demonstration of advanced control systems for complete power plants

Résumé

Due to recent advances in process automation, various tools for computer-aided process control have become available. This progress will also support advanced solid fuel-based electricity generation processes in terms of maintaining their features even in difficult operational situations. Thus, the advanced control system will increase the overall efficiency, reliability and availability of advanced solid fuel-based electricity and heat generation technologies. This will help these advanced technologies to be more economic and competitive.

ADOPTION OF CLEAN COAL TECHNOLOGY IN APEC COUNTRIES

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ABSTRACT

The Asia Pacific Economic Cooperation (APEC) economies represent a major sector of Asia. In most of these economies there is a need for growth in power generation and supply greater than in any other large region. These economies are generally moving toward a competitive electricity market concept and to allow international ownership of power facilities. Some are much more advanced than others.

The region has significant power generation from low sulfur coal and is committed to expansion of generation from coal, unlike some other regions. Conventional coal fired plant is being installed by both government supported monopolies and by independent power producers. While there is competition from other energy sources coal remains one of the cheapest sources of electric power.

The greater environmental awareness developing in these economies can be supported by promoting and utilizing clean coal technology tailored for the low sulfur coals available in the region, thus minimizing environmental and greenhouse problems.

There is a lack of awareness of the advantages of clean coal technologies that the APEC Expert Group on Clean Fossil Energy and others are attempting to remedy. Seminars and training courses have been presented with more than 500 participants from the region. Asia is interested in new technology and in the possibility of moving beyond conventional technology to a more efficient power system.

The recent financial problems in the region do not change any of these aims or directions. Governments will have reduced funds to allocate to power infrastructure and will welcome private initiatives. Innovative offers for this technology in a region not averse to coal and needing additional plant need to be made, stressing the environmental benefits in addition to the improved efficiency. Specific economies are discussed.

1. INTRODUCTION

The present economies belonging to the Asia Pacific Economic Cooperation (APEC) group are set out below. They represent a major proportion of the Asian economies linked with the Pacific Ocean. Recent members Russia, Peru and Vietnam joined the group in 1998.

Australia, Brunei, Canada, Chile, PRChina, Chinese Taipei, Hong Kong, Indonesia, Japan, ROC Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Thailand, USA, Vietnam.

Some basic indicators for these economies are listed in Table 1.

Table 1 Population and GDP information*

Economy	Population,m	GDP/Head,US$
Australia	17.8	18,000
Brunei	0.28	17,000
Canada	30.6	21,220
Chile	14.4	5,875
PRChina	1209	530
Chinese Taipei	21.1	12,288
Hong Kong	6.1	21,650
Indonesia	190.7	880
Japan	125.2	34,630
ROC Korea	44.5	8,260
Malaysia	19.7	3,480
Mexico	95.1	4,505
New Zealand	3.5	13,350
PNG	4.0	1,240
Philippines	68.6	950
Russia	146.7	3,240
Singapore	2.9	22,500
Thailand	58.7	2,410
USA	270	31,230
Vietnam	72.5	200

* All figures are the most recent available but year may very slightly from country to country. Sources: The world in 1998, Pocket Asia, The Economist and other.

2. ENERGY MIX AND GROWTH

APEC economies have a diverse mix of energy sources based upon previous government initiatives and some aid programs from western economies. These range from high dependence on coal such as in Australia and PRChina to other economies heavily dependent on oil. In most regions there is an increasing interest in gas. The region is also interested in utilizing waterpower and increasingly in nuclear power.

Power systems in many APEC economies tend to be relatively small and in some cases fragmented. Quite often the transmission system lags behind the provision of generation capability. Individual generation unit capacity needs to be about 300 MW in most cases to match unit capacity to power system size and retain system stability. In some cases there has been a high proportion of one energy source utilized leading to potential reduced power system stability.

Some economies realize the problems that may be associated with a particular energy resource mix for technical and economic reasons. They are investing in other forms of generation to result in a better energy mix.

Both the International Energy Agency (IEA) and the World Bank (WB) have made statements recently about the future growth of the Asian region that contains the major APEC economies. These have been made as a result of the currency fluctuations in the region in late 1997. The IEA suggest that recovery will be effective by 2000 but that independent power producers and others will have problems until then because of reduced demand for power. Energy demand will then rise rapidly to 2020.

The WB has also outlined a tough situation for the immediate future. It is concerned with sector reform and means of achieving this.

3. CLEAN FOSSIL ENERGY EXPERTS WORKING GROUP

The APEC Secretariat has a number of Committees focusing on various aspects of matters of common interest. Within the energy arena a Clean Fossil Energy Working Group has been active for some time. The Aims of this Group are to foster and assist in the development of coal and other clean fossil technology in the member economies. A recent modification in the title of the group signifies the wider scope accepted by the group to include technologies such as the development of coal seam methane.

The Experts Working Group was initiated in 1992. Funds are made available from the APEC Secretariat for worthwhile projects to study and report on the fossil energy changes in the region or to promote technology transfer by means of training courses, seminars, workshops and visits to clean coal technology facilities. In general APEC economies fund the attendance of their representatives at necessary meetings.

It is an active group in providing access to the latest information on these technologies. It promotes the use of clean fossil energy technologies, as they become commercially available. It has regular business meetings that are usually held in conjunction with other initiatives.

For some years it has held an annual Technical Seminar in a different APEC economy. These are well attended with the majority from the host economy and lesser numbers from their economies. Speakers are chosen for their technical knowledge and are drawn from as many economies as possible.

It has held two training courses in CCT with participants from many APEC economies. These courses were for two weeks. The first was held in Australia and the second in Japan. Courses have been limited to about 20 participants to ensure effective tuition.

The Committee is also concerned with major projects demonstrating new technologies or new applications. The major project at present is a coal seam gas development in PRChina that is at the project formation stage.

It has recently published a review of air quality standards and emission from coal fired power stations in APEC economies.

The economies within APEC are concerned with all aspects of clean fossil energy. Some provide the technology, such as Japan and the USA. Some provide additional coal where necessary, such as Australia and Indonesia. Others are excellent prospective applications of appropriate technology such as PRChina, Malaysia and Thailand.

4. ROLE OF COAL IN APEC

The increased interest in the environment in general and greenhouse gas release in particular has caused a move away from coal as a primary energy resource in some parts of the world. In general this is not the case in APEC countries and coal is well received, particularly for the low cost energy it can provide. Asia has a more balanced view of coal compared with Europe and other continents.

It should be noted that the APEC region has ample reserves of low sulfur coal (~1% or less), either local or imported from within the region. This has minimized the need for major flue gas desulfurization plant on conventional coal fired power stations except for a few specific cases. Some APEC economies are legislating for desulfurization in the future that will assist in the introduction of CCT.

Many of these economies are developing and constructing conventional coal fired power stations now. These are being undertaken by existing government supported monopoly (GSMs) utilities, independent power producers (IPPs) and merchant power producers (MPPs).

Examples of conventional coal fired power stations presently being installed are:

Australia (Collie),
PRChina (numerous),
Chinese Taipei, (Mailiao, Hadoer, Huatung)
Indonesia (Tanjung Jati),
Japan (numerous),
Malaysia (Janmanjung),
Philippines (Sual),
Thailand (Prachuab Khiri Khan, 304 Industrial Park),
Vietnam (Pha Li)

In addition to this APEC activity some other Asian economies are active in installing coal fired plant including India (numerous).

There are of course major increases in every energy source in the region, from nuclear to waterpower. However coal is seen to be necessary for the future of the region. To reinforce this a recent publication sets out the likely demand for coal in the region through to 2020.

Table 3 Coal demand in Asia (Mtoe)

	2000	2010	2020
Australia	43	48	56
PRChina	835	989	1400
India	165	255	360
Indonesia	10	20	44
Japan	92	95	97
Korea, South	38	46	63
Malaysia	3	5	10
New Zealand	1	2	2
Pakistan	3	9	21
Philippines	3	5	11
Chinese Taipei	20	31	43
Thailand	8	16	34

Source: Power in Asia, Issue 245

This continuing interest in coal augurs well for substitution of clean coal technologies (CCT) for present conventional power stations either for new plant or for effective repowering of older plant. It also provides a path for power stations using expensive oil or gas products to consider installing a gasifier to allow the use of cheaper coal. This may be valuable in providing assurance of energy source and in stabilizing energy resource costs where alternative sources are available.

5. COAL AND THE ENVIRONMENT

All of the APEC economies have significant concerns for the environment. The attitude of many economies is somewhat different from Europe and the US in the allocation of priorities to environmental matters. Improving the quality of life of the population by the provision of electric supply is seen as a key political initiative.

These economies tend to place improving the health of the population, that is local environmental problems, ahead of international environmental matters such as considerations of greenhouse gas emission.

There is also a strong incentive to develop an efficient society and in many economies this takes precedence. Notwithstanding these attitudes there is a commitment to utilizing coal absent from some other parts of the world and the CCT industry should assist these economies to meet their needs with technology which addresses their environmental and development aspirations.

6. GOVERNMENT AND PRIVATE INVESTMENT

The financial events late in 1997 and subsequent devaluation of currencies in many APEC economies and increase in local inflation rates is of concern to all. It has produced a period of uncertainty, some economies being affected much more than others, and taking longer to come to terms with the new reality.

In general, Asian APEC Governments are stretched more than previously with respect to financing new infrastructure such as power stations. The financial situation has also dampened the need for power but this seems to be a relatively small reduction. Governments have better things to do with their reduced income and will be much more receptive in allowing private finance to assist in developing new infrastructure.

The World Bank provides the following estimates for infrastructure finance from 1995 to 2004 in US$b. for the region. and shows the scale of need. The present financial position in some economies will trim these figures but the thrust remains the same.

Table 4 Investment required for infrastructure 1995-2004 US$b.

PRChina	200
Indonesia	82
Korea	101
Malaysia	17
Philippines	19
Thailand	49

PRChina is a good example of an economy with major power projects utilizing coal in APEC. A number of power stations with 660 MW units have been approved and some are already in service. PR China also has had many atmospheric fluidized bed units in service for some years.

Again, in Malaysia a number of power stations exceeding 1000 MW using coal are being built and commissioned now. Some of these power stations are being installed by GSMs and some by IPPs.

Any of these could have been using CCT and the achievements of new demonstration plants in the Netherlands and the USA need to be actively promoted to show that the perceived added risks are manageable. The availability of demonstration CCT power stations is now well above that in many APEC economies present conventional coal fired plant.

The first Asian clean coal technology plant outside Japan was proposed for India to complement the operation of a cement plant but the 50 MW project seems to be delayed at the present time.

Some APEC economies have large oil refineries and this may well be a means of bringing the technology to the notice of prospective clients. About 1000 MW of integrated gasification combined (IGCC) cycle plant is being built and commissioned now in Italy at oil refineries to provide hydrogen and energy from otherwise environmentally unfriendly heavy residuals. The technology for gasification of residuals is similar to that for coal.

7. ISSSUES IN DEVELOPMENT OF CCT

There are a number of issues critical to the promotion and marketing of CCT in APEC regions. These are listed below, not necessarily in order of importance as this varies from economy to economy.

7.1 BASIC ISSUES

Energy growth

The first issue is the continuing need for power and growth in the electric power industry. The financial situation may have temporarily slowed this but there are still very large potential markets.

Indigenous resources

Additional power generation should take advantage of indigenous resources in every economy where economically sound. Coal is recognized as a major domestic resource in many APEC economies and should be utilized in the most efficient and environmentally advantageous manner as possible. CCT utilizes this resource in a manner that provides 25% more energy and does so with far less interference to the environment than conventional coal fired plant.

The utilization of imported coal may be advantageous in some regions where local coal transport problems exist to supplement and complement indigenous supplies to provide an optimum feed composition for a specific type of CCT gasifier.

7.2 POLITICAL ISSUES

Extent of overseas ownership and control

APEC governments have liberalized the conditions for international development and ownership of power projects. Allowing international energy organizations to assist the government in providing power for future releases funds for the government to utilize in ways more politically visible to the population. New or repowering CCT plants fall into this category.

Competitive electricity market

Many APEC economies have embarked on promoting a competitive electricity industry. In the longer term this will improve their competitiveness in international trade. Competitors in the new electricity market tend to seek generation projects with reduced capital costs and higher long term costs. This is brought about by the difficulty in raising initial capital and results in higher prices for power in the longer term.

CCT has slightly higher capital costs than some other technologies but promises far lower operating costs and resulting reduced tariffs. Government policy should support this type of installation to compete with the lower capital cost options.

Importation of energy resources

APEC economies import a range of solid, liquid and gas resources to complement their own energy reserves. These imports require foreign exchange allocation and are therefore of concern to the respective government. CCT provides a route to reduce the consumption of more expensive liquid and gas fuels and also to conserve foreign exchange.

Awareness of CCT

Clean coal technologies provide an effective combination of improve efficiency, environmental health and greenhouse issues together in a common package.
There appears to be a lack of awareness of the economic capabilities and environmental benigness of the new coal technologies both on the part of Government, GSMs and IPPs, which needs to be addressed.

The APEC Experts Group on CFE, the United Nations Development Programme (UNDP) and others are attempting to remedy this deficiency. Seminars and training courses have been presented with many participants from India.

7.3 TECHNICAL ISSUES

Proven unit capacity in CCT

The new demonstration clean coal technology plants in Europe, Japan and the US are of about 250-300 MW capacity. These are ideal additions to the existing power systems in many APEC economies without compromising stability. The availability of most of these demonstration plants now is greater than some existing conventional coal fired power stations in APEC economies.

Potential for repowering older stations

Many coal-fired power stations in the region are over 20 years old and could benefit from repowering. Conventional wisdom would refurbish these to their previous nameplate capacity and efficiency at a cost. Consideration should be given to repowering these at somewhat higher cost but with much greater returns for investment.

An excellent example is the demonstration IGCC plant at Wabash Power Station in the US. This repowering took a 100MW unit downrated to 90 MW with 30 % efficiency and returned to service a 252 MW unit with an efficiency of about 38%. The application of this technology to appropriate coal fired units would increase their capacity by about 2.5 times for those units selected and do this with a significant increase in efficiency.

Matching technology with available coal

There is certainly a need for a clean coal technology that complements the available coals in the region. Most present technologies have been designed to utilize coal with a sulfur content up to 4%. Most of the coal in or economically available to Asia is 1% sulfur or less. Significant capital cost reduction can be achieved if designs suitable for the available fuel are used.

Reduced water demand for CCT

The reduced water consumption of an IGCC compared with a conventional coal fired plant is highly significant in locations where the installation of a conventional plant is marginal because of limited water for cooling. Installation of IGCC technology allows a greater output to be installed given a fixed availability of water quantity.

Technology transfer for CCT

This implies a positive level of technology transfer from those economies with new technology plants available for export to those economies wishing to use the most efficient and environmentally benign technologies. The CFE Experts Group have done much in this area.

7.4 ENVIRONMENTAL ISSUES

Local environmental issues

Most APEC economies have an increasing concern for the health of the population and the environmental matters contributing to this. Any new energy installation raises some environmental concerns. The advantages of CCT become evident when compared with conventional coal fired technology. In particular the sulfur oxides and nitrogen oxide release is dramatically reduced. This will improve the situation if an existing power station is repowered with CCT.

International environmental issues

In the same manner international concerns over the release of greenhouse gases are catered for because the CCT have an increased efficiency of at least 25%, with a corresponding reduction in greenhouse gas release.

7.5 FINANCIAL / RISK MANAGEMENT ISSUES

Reliable operation of CCT

Europe, Japan and the US have invested in demonstration CCT power stations with a total capacity of more than 1000 MW. While the plant availability of some of these was not high in early operation all of these plants now have satisfactory availabilities. Most of them have figures better than some existing conventional coal fired units in APEC economies.

Capital cost of CCT

While the capital cost of demonstration power stations in the US, Japan and the Netherlands was high the quoted costs associated with new CCT plants are nearly equivalent to conventional plants using coal, particularly if designed specifically for low sulfur coal.

Energy resource security

There has been concern, especially by IPP and MPPs about guarantees of energy resource supply. This is particularly the case with some liquid and gas fuelled IPP power stations. Reliability of supply can be improved significantly by installing a coal gasifier. This allows a choice of gas, liquid or coal where these are nearby rather than depending on one fuel resource alone. The availability of two energy resources also assists in stabilizing the price of fuel.

Reduced time to profitable operation

The installation of a coal gasifier with a combined cycle gas turbine allows a 24 month construction cycle to first power from gas or liquid fuel with a further 12 months to have the gasifier operating in parallel with the combined cycle plant. This combination of plant results in short project time to profitability needed in a competitive market together with the longer term reduced operating cost from using coal.

Perceived risks associated with CCT

There are some additional perceived risks associated with a project supporting the installation of CCT over a conventional coal fired power station. These risks need to be identified on a case by case basis, isolated and acceptable solutions to each one promoted to ensure the risks are reduced to a minimum and are shared in an acceptable manner among the participants.

8. TECHNOLOGY AWARENESS

In addition to the efforts of the APEC experts group on clean fossil energy (CFE) other organizations such as the United Nations Development Programme (UNDP) have also been training participants from most of the economies in the region. The UN has trained over 1000 participants from government, GSMs and some IPPs in coal fired power station technology with reference to CCT. More work needs to be done, particularly to provide information on the demonstration plants and their improving availability and forced outage rates.

These training courses are focused on particular groups and range from informing senior government policy managers to actual plant operators in a series of tailored courses.

9 APEC MARKET FOR CLEAN FOSSIL ENERGY

There are a number of economies where opportunities exist now.

In Australia there is a need for additional coal fired generation in Queensland which has a reduced reserve margin in its power system. Expressions of interest were called and a number of power stations utilizing coal were proposed. A number of independent generators have announced coal-fired units with capacities up to 700 MW. These consortia are investigating all possible technologies to be able to compete in the electricity market in a few years time when the plants are operational. Legislation in at least one State has made consideration of the impact of greenhouse gas release critical for new plant proposals.

PRChina has announced that it is closing down many older small coal fired boilers and power stations and replacing them with new plant. The standard replacement is conventional coal fired units but some of these could be induced to incorporate CCT. It also has one of the biggest expansion programs for generation over the next 20 years, which includes plant using PRChina's main energy resource, coal.

Chinese Taipei has accepted significant IPP proposals for coal fired plant. Stage I included about 3650 MW of plant utilizing coal with much of this to be operational by 2001. Further expansion, including plant using coal is such that between 1997 and 2006 a further 20,000 MW is needed. Effective marketing should enable a significant portion to be CCT.

In Malaysia the 1500 MW conventional coal fired power station proposed for Penang has been delayed. This provides the window of opportunity for a change to clean coal technology, particularly for a tourist destination such as Penang.

The Philippines is building a 1000 MW coal fired power station at Sual due to be completed by 1998. Further units could well utilize CCT if their qualities are promoted adequately.

Thailand is building a coal fired cogeneration plant at an industrial park. This is a move in the direction of higher efficiency plant.

Vietnam has contracted for a new coal fired power station at Pha Li burning anthracite.

Outside APEC India has an energy mix highly dependent on coal so that clean coal technology could be implemented there for new plant or for repowering older plant. India has just announced a series of IGCC plants to treat heavy residuals from a number of oil refineries. This indicates recognition of the advantages of the new technologies.

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THE BENEFITS AND OPPORTUNITIES
FOR
CLEAN COAL TECHNOLOGY DEVELOPMENT IN AFRICA

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ABSTRACT

The African continent provides technology a unique opportunity to inform, develop and install efficient, environmentally sound electrical infrastructure moving into the next millennium. Africa is a continent with major cities not fully electrified and the vast majority of rural communities unelectrified.

Africa is a continent with close to 80% of the population unelectrified. With the world's business sector seeking new opportunities, many should look closer at development in Africa. Africa is a continent having large coal reserves that will provide opportunity for the deployment of clean coal technology for large to small installations. This type of selective carefully planned development is crucial to preserve the delicate environment and wildlife of Africa.

The lessons learned in the United States and abroad can be transferred to Africa to provide cost-effective development. Providing generation that is safer for the environment and the customer base it serves.

Many rural communities utilize cheap, raw coal for heat and cooking in their homes. Educational programs addressing the dangers of such practices are a necessity. To further influence change in usage, substitutes for the coal must be developed to produce the same amount of heat and provide a cheap alternative.

Combining the high technology alternatives, with grass-roots education for home usage will provide Africa with the means to address its delicate environment and provides expansive opportunities for companies looking for new ventures to conquer.

This paper will provide an over view of the clean coal industry and the opportunities Africa presents this industry, moving into the next millennium.

WHAT IS AFRICA?

Good morning, I am John Butler, Executive Director of the African Electrification Foundation. AEF is a non-profit organization based in Los Angeles, California, which specializes in providing technical and managerial assistance to energy infrastructure development in Africa. Today I will be addressing the topic of Africa, the African Energy Sector and opportunities within this sector.

Africa, mother of mankind, cradle of civilization, creator of technology, math and the sciences, is referred to by most as one country, but has more than 50. Africa, seen through its wildlife and beautiful natural wonders - but not for its cities. Africa, known for its civil wars and starvation -

not for its stability. But for many, it is still the Dark Continent, known through brief flashes of negativity on the nightly news.

So what is Africa today? Africa is where less than 25% of the continent's population has access to electricity. Major cities are not fully electrified and the vast majority of rural communities are unelectrified. Africa is a continent experiencing a multitude of political, social and economic challenges. Political stability has been maintained by some and recently come to many other countries, but there are still nations experiencing internal strife. With political stability comes governmental responsibility to uplift the standard of living for its citizens. It is therefore, imperative that nation by nation and region by region, development in Africa take on a new form. A form that will be consistent, long-term and have a significant impact on the over 600 million people who reside there.

The African continent is blessed with an abundance of natural resources, conducive to producing fossil, hydro or renewable energy electrical generation. The multitude of rivers that traverse the continent provide tremendous potential for hydro generation. Consistent exposure to solar rays creates a fertile environment for photo-voltaic usage. The Southern region is rich in coal, and the North, East and West regions have had new oil and natural gas discoveries.

Yet, Africa currently lacks the widespread modern technology needed to maximize these natural resources. Low cost electrical development, coupled with energy efficiency, environmental ethics and industrial development, will overtime eliminate Africa's infrastructure dilemma. The African continent provides technology a unique opportunity to inform, develop and install efficient, environmentally sound electrical infrastructure for the next millennium.

Modern technology can alleviate poor maintenance of power supply and telecommunication systems. Environmentally sound long-term industrial development will utilize new energy generation and provide a base for large, medium and small business development. As shown in the U.S., the economic stability of any nation's business sector is its small and medium business development.

With the world's business sectors seeking new opportunities, many should look closer at development in Africa. Southern Africa is a region of the continent having large coal reserves that will provide opportunity for the deployment of clean coal technology from large to small installations. This type of selective carefully planned development is crucial to preserve the delicate environment and wildlife of Africa.

THE REPUBLIC OF SOUTH AFRICA ENERGY OVERVIEW

The southern region of Africa contains the largest producer of electricity and user of coal for electrical generation on the continent, ESKOM. ESKOM, the electric utility of the Republic of South Africa is the fifth largest electric utility in the world. ESKOM produces 95% of the electricity generated in RSA. Close to seventy-five percent (75%), of its electrical generation is fueled by coal. The stage is set in RSA and neighboring countries such as Botswana, Zimbabwe and Tanzania, for viable industrial development in clean coal technology, that will, in turn, bring positive economic and environmental growth.

Electrical generation is one of the most important components to modern infrastructure development. It is the foundation for industrial growth and prosperity. ESKOM, through its own initiatives and the RSA government's Redevelopment Program, has initiated an electrification campaign goal to electrify 400,000 homes per year by the year 2000. Their progress is shown in Table 1.

Table 1 - .Eskom Electrification Statistics

Number of connections made in:	1994	1995	1996	Total of connections 1994-96
TOTALS	254,383	313,179	307,047	874,609

This electrification program, coupled with increases of connections in neighboring countries, will necessitate the development of clean, efficient, environmentally sound electrical generation. The lessons learned in the United States and abroad can be translated to Africa. The goal: providing cost effective generation that is safer for the environment and the customer base it serves.

Why International Involvement?

There are two important components in the transfer of waste coal reprocessing technology to RSA. The first--a need in the RSA. The second - the current American state-of-the-art technology will adequately fill the RSA stated need.

Economic development on the African continent will necessarily be accompanied by increases in energy consumption. The global ecology is of concern, however, as energy consumption increases, improvements in the developing regions can cause changes in the loading of greenhouse gases to the atmosphere, as well as other pollutant generation. Internationally, it is recognized as essential that increases in energy consumption due to improvements in developing regions stress efficient energy choices, within the context of cost effectiveness and given the limited resources available.

Coal is an important component of RSA's energy resources. Like the U.S., coal is the dominant fuel for electric power production in RSA. Coal use produces by-products that can have detrimental effects on the environment if improperly managed.

In the past, there was little incentive to utilize discard coal, but this thinking has changed as technologies have been developed that permit economic recovery of energy from waste coal. In America, businesses increasingly view waste coal piles as an economic asset.

Why International Involvement?

From an international perspective, the use of fuel reclaimed from coal refuse as a low cost energy source is an attractive proposition. The development of this industry could spur economic development and emission reductions in the majority of residential regions in RSA.

This concept concurs with recent research conducted in the RSA focused on coal refuse as an economically attractive energy source in these regions.

Pollution Prevention and Control.

Using waste coal efficiently minimizes not only environmental concerns about global warming and active generation of pollutants but will also minimize and prevent future run-off pollution that results from stockpiling waste coal. Within the RSA there are expansive piles of coal waste causing the government and industry tremendous environmental concerns.

RSA coal for local electricity production is amongst the cheapest in the world. Because of the relative high ash content of RSA coal, it needs beneficiation to be acceptable on world steam coal markets. This is achieved by washing, which results in a 30% discard rate. As of 1995, 500 MT of discard stockpile had accumulated.

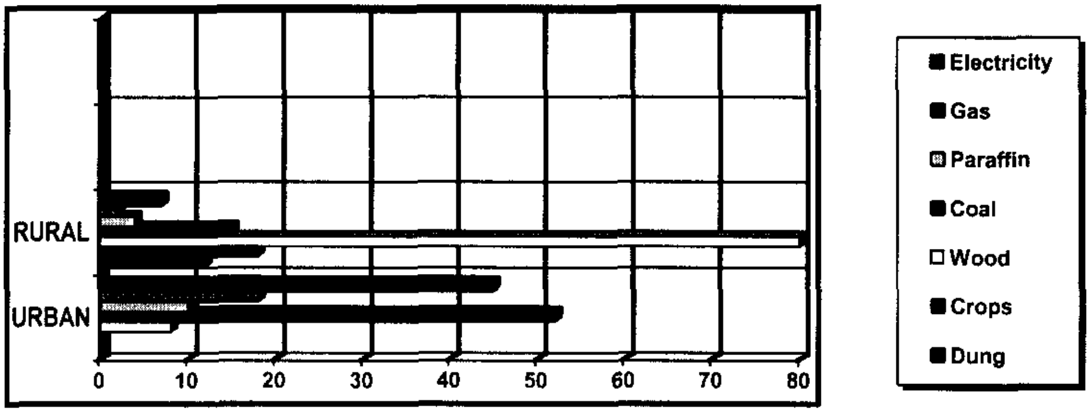
The energy derived from reprocessing these tons of coal waste can be used to provide energy for electricity, heating, cooking, as well as the building blocks for construction of homes and the laying of pavement. Other environmental concerns are addressed by enhancing infrastructure development, construction and housing development, medicine, agriculture, education, long term environmental considerations and the introduction of low cost electrification using renewable energy in rural areas.

In addition, there is a significant air quality problem related to coal use in space heating within townships. Coal is used by approximately 950,000 households. Significant research by the RSA government has focused on this material as feedstock for Low Smoke Fuels production. The objective of Low Smoke Fuels production is to provide competitively priced fuel produced from discards, with smokeless combustion properties, for use by township residents. The objective is to replace all household use of bituminous coal by the year 2000.

Fuel recovered from RSA coal refuse is being examined as power station fuel and for gasification for synthetic fuels production. As previously mentioned, in the past, the coal industry had little incentive to use discard coal. This has changed as technologies have been developed that permit economic recovery of energy from waste coal. Today, waste coal piles are seen as an economic asset. The RSA Department of Mineral and Energy is interested in addressing these issues of coal piles utilization in RSA. This represents a significant export opportunity.

As of 1995, only half of RSA's 9 million homes, had access to electricity, 75% in urban areas and 20% in rural. The aforementioned electrification program, has objectives to provide access to 70% of the households by 2000. Mid-to-high income households utilize electricity to satisfy their energy needs. Low-income households with access to electricity, still utilize cheap, raw coal for heat and cooking in their homes. Multiple fuel use is also common in non-electrified homes. The fuels used are paraffin (kerosene) for lighting, cooking and heating; coal for cooking and heating and wood fuel the main fuel for cooking and heating in rural areas.

Table 2 - Domestic Fuel Mix



Type	Dung	Crops	Wood	Coal	Paraffin	Gas	Electricity
Urban	0%	0%	8%	52%	10%	18%	45%
Rural	12%	18%	80%	15%	4%	2%	7%

For some a house is not a home without a fire blazing that provides heat. Educational programs that address the health dangers of such practices are a necessity. Attempts to introduce efficient coal stoves have been rebuffed. To further influence change in usage, substitutes for coal must be developed to produce the same amount of heat and provide a cheap alternative.

Combining high technology alternatives, with institutional and grassroots education for home usage will provide RSA the means to address its delicate environment and provide expansive opportunities for companies looking for new ventures. Tuskegee University in Tuskegee, Alabama, is addressing just such measures in a joint venture with the U.S. Department of Energy and RSA institutions.

Coal refuse as an energy source is attractive from both an economic and environmental standpoint. However, as this still represents the use of a non-renewable fossil fuel, the specter of emissions must still be addressed. Maximum cost effective efficiencies should be established for the use of this type of fuel as an energy source. In order to minimize the increased carbon dioxide loading that results from economic development, it is fundamental that any increase in energy consumption be approached from the standpoint of maximum efficiency in its generation and use. Optimum efficiency would also provide an effective platform for addressing other pollutant clean-up requirements.

Effects on the Economy

Efficiencies associated with the use of fuel derived from coal refuse can be related to the type of system that produce energy from fuel, as well as fuel quality. Both of these considerations must be examined in detail as part of project development.

Effects on the Economy

The availability of low cost energy is essential to the improvement of the economy in a developing region. Coal waste is under consideration in the RSA and, as seen in American practice, there is a wide variety of means by which coal waste can provide energy for the residential, commercial and industrial sectors. In the near term, it can be assumed that increases in energy consumption in the majority of RSA townships will primarily be in the space heating and power generation sectors.

This can simplify and reduce costs associated with a study to minimize increases in atmospheric carbon dioxide loading, as a narrow range of fuel quality and utilization systems can be envisioned.

In the space heating sector, current fuels include wood and coal. Current conditions include significant hydrocarbon emissions, an indication of inefficient combustion. Additionally, the use of wood as fuel on the African continent is undesirable from the standpoint of desert encroachment. As such, the use of fuel from coal refuse can mitigate problems that may be more serious than carbon dioxide emissions.

However, there is potential for reductions in carbon dioxide emissions through the use of space heating fuels of uniform quality, tailored to produce maximum efficiency in available space heating combustion systems in the region. There is the potential to assure maximum energy efficiency in the domestic heating sector.

Through a capacity building initiative, there is added value not only in the extraction and effective utilization of waste coal, but also the benefit of a grassroots and institutional efforts for technologies in RSA. The long-range objective of the capacity building effort will be the creation of businesses around waste coal recovery activities. The economic implications will effect job creation and income generated. The social implication in terms of the labor that is required for the enterprise, and other related enterprises, (e.g., suppliers and distributors) will be impacted in a positive manner.

Improving Public Health

There is widespread use of coal ovens for domestic heating and cooking that results in high particulate emissions of SO2 and NOx in residential areas. Through capacity building efforts, the potential for electric generation utilizing waste coal is enhanced. Thus reducing the potential for uncontrolled domestic burning of waste coal derived fuels. This should improve air quality and positively impact public health.

Technology and Information Transfer

U.S. leadership in developing and using technologies to recover energy from waste coal is well established. The RSA represents the largest market opportunities for export of these technologies on the African continent.

To succeed in the RSA, the goal of any business would be, (1) to combine technical information and business infrastructure to support/increase the market, and (2) capacity building as focused on the transfer of business practices. Such an initiative would support RSA goals to make better use of energy resources through improved planning/management.

It also supports RSA objectives to provide equal opportunities for all its citizens through improvement of education, in addition to encouraging business entrepreneurship and training. With the inclusion of business, government and education in both the U.S. and the RSA the potential for building stronger positive, bi-national ties will be enhanced. This provides an opportunity to marry appropriate American business management practices (e.g., total quality, quality improvement and customer orientation) and RSA practices that enhance the effectiveness of technology packages delivered. The ultimate result could be the establishment of joint commercial operation for the production of domestic fuel (near term) and circulating fluidized bed boiler fuel (long-term) from RSA coal waste.

Once an appropriate technological benchmark has been established then issues such as: methodology (chemical vs. gravitational); power generation philosophy (baseload vs. peakload); central vs. decentralized power stations and combustion (internal vs. external solid, gas vs. liquid) can be addressed.

Feasibility studies would address waste coal in quantity, location, composition, owners and local meteorological and climate conditions. What is needed is 1) technology appropriate for recovery of fuel from coal waste using coal preparation and historical information and 2) the technology of Circulating Fluidized Bed power generation technology using coal waste as fuel. There are 11 Circulating Fluidized Bed commercial projects in the U.S., and 40 clean coal demonstration projects in all, (see attached listing). In Pennsylvania and West Virginia, there has been significant commercial use of coal waste ash in the production of lightweight concrete masonry units used in the construction of housing. This type of technology would enhance the directive of the RSA RDP to provide housing to the populous.

The RSA Coal Market

RSA coal utilized for electricity production is amongst the cheapest in the world. The types of mining are:

Table 3:

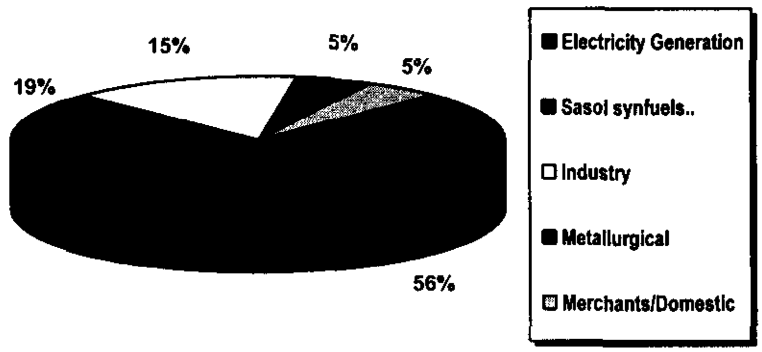
Mining Methods	%	
Open pit		49.7
Bord and pillar		33.6
Pillar recovery	12.1	
Long-walling	4.6	

There are about eighty collieries active, ranging from the largest in the world, to small-scale producers. The largest RSA producer, Ingwe Coal, is the world's largest exporter of steam coal and the third largest individual coal producer. The three largest coal mining companies – Ingwe, Amcoal and Sasol – accounted for 80% of 1995 production.

Including the next three largest – Iscor, Duiker and JCI, and, collectively, these six account for 96% of production.

Table 4:

(Coal Uses in RSA Local Market)



Electricity generation	56%
Sasol synfuels, gas & chemical production	19%
Industry	15%
Metallurgical	5%
Merchants/Domestic	5%

In addition, RSA has sizable coal bed methane resources tied to large coal reserves, which have not been utilized.

Creating a Win-Win

Reprocessing of coal refuse for energy recovery has been practiced in America for over 100 years. Conventional coal preparation equipment has been successfully adapted for the purpose of providing high specific gravity separations and handling large percentages of rejects that are characteristic of the process. The technology is commercially available and examples in commercial operation are found in Pennsylvania and West Virginia.

Potential economic uses of waste coal run the spectrum from briquettes for home cooking and heating, to efficient electrical power generation for electrification of majority residential areas or townships to activated carbon production for environmental cleanup applications.

This technology is in place to fill power station demands amounting to over 10 million tons of fuel per year recovered from coal refuse. This type of business is relatively less capital intensive per unit output as compared to a new mining operation.

To aid in the start-up of coal refuse reprocessing ventures, as well as, spur the introduction of American technology, a technology package must be assembled, which includes a comprehensive report on the recovery and use of fuel from coal refuse. Computer simulations of American coal refuse reprocessing circuitry can be applied to RSA refuse analyses.

RSA has been a leader in the implementation of advanced coal technology, yet little commercial development of coal waste use has taken place. The RSA government has recognized the need to introduce technology for waste coal utilization. The U.S. is ahead of RSA in this area. Thus there are opportunities for U.S. technology export. This approach focuses on relatively low quality coal waste. It addresses emerging markets in Africa. No adverse competition is anticipated with American coal exports. Thus, a potential win-win situation for all.

OPPORTUNITIES

The following examples demonstrate the many opportunities available to aggressive, focused firms. There are opportunities for small, medium and large businesses in Africa.

Areas of potential investment:

- Administrative services
- Billing techniques
- Clean coal technology and related services
- Commercial services
- Customer service techniques
- Community relations
- Distribution system development
- Engineering consulting
- Energy efficiency techniques
- Energy saving products
- Environmental technology and services
- Equipment, (i.e., alternators, circuit breakers, electric cables, electric motors, gas generators, gas turbines and parts, generator sets, hydraulic turbines and parts, metering boxes, relays, steam turbine generating units, solar energy systems and parts, solar panels, switchgear, transformers, utility poles)
- Human resources
- Information systems
- Legal restructuring of energy investment systems
- Management services
- Power facility purchasing and management
- Power pool development
- Pre-payment meters
- Renewable energy technology
- Training
- Transmission line planning

An example of the opportunity for imports to Sub-Saharan Africa in energy sector products or related materials are as follows:

Table 5:

Imports from the U.S.	In Millions of Dollars (1994)
South Africa	91.6
Ghana	5.3
Kenya	3.3
Cameroon	2.8
Nigeria	2.7
All other	7.9
Total	**113.6**

Total U.S. imports for minerals and metals were in millions of dollars - 147.8; for transportation equipment - 34.1; for electronic products - 28.5; for machinery - 44.1. There is still room for growth in these and other areas.

Sources of Funding

Perhaps the greatest incentive for seeking opportunity in Africa is the availability of private and public capital for private sector ventures. OPIC's five direct investment funds, totaling $440 million, were established in March 1996.

In 1994, USAID and the U.S. State Department authorized the establishment of a $100 million Southern African Enterprise Development Fund.

The African Export-Import Bank commenced operation in November 1994. It has authorized capital of $750 million, with current subscriptions of almost $500 million.

IFC has also established a $30 million investment fund called the African Emerging Markets Fund. These are but a few of the major financial institutions signaling opportunity in Sub-Saharan Africa.

SUMMARY

Africa is on the brink of a dynamic industrial explosion. The international community must become an active participant in this economic growth. The opportunities for small to large firms are vast. The sheer size of Africa alone provides companies with a myriad of opportunities to compete in this market. The majority of international firms, with the exception being former colonizers, have not looked at Africa as a viable source of business in the past. The formation of new stable governments in many regions bodes well for opportunity.

Africa calls to the international community seeking advanced technology and expertise. Africa's past experience is predominately European. North and South America, Asia and the Pacific Rim can also provide a fresh new approach to the enormous electrification, telecommunication, transportation and economic needs of Africa.

Regional organizations such as: the Southern African Customs Union, Southern African Development Community, the Common Market for East and Southern Africa, the Economic Community of West African States, West African Economic and Monetary Union, Mano River Union, Customs and Economic Union of Central Africa, Central African Customs and Economic Union, Economic Community of Central African States, the Economic Community of the Great Lakes Countries, Maghreb Permanent Consultative Committee and the Indian Ocean Commission, must market and promote the opportunities they represent to investors in their regions of Africa.

U.S./Africa trade reached a new high in 1995 propelled by a 26.6% surge in sales with South Africa and a partial recovery of sales to Nigeria. The U.S. purchased more than 18% of Africa's exports, yet the U.S. is only the fifth leading industrial country supplier to Africa. Africa increased its purchases from Korea and Thailand, causing an overall decline in purchases from the Big Five: France, England, Germany, Japan and the United States.

South Africa and Nigeria are the dominant importers of U.S. products, (62%) of all U.S. exports to Africa. But Sub-Saharan Africa is less than 1% of all U.S. exports. Yet U.S. exports were 54% higher than exports to the newly independent states of the former Soviet Union.

Eight countries account for more than 80% of U.S. exports to Africa: South Africa, Nigeria, Angola, Cote d'Ivoire, Ghana, Ethiopia, Zimbabwe and Kenya. Direct U.S. investment in Sub-Saharan Africa, by non-bank affiliates, generated net income of over $1 billion in 1994, a 30% return on book value, compared to an 11% return worldwide. The average book value returns for 1990 through 94 were 28%, compared to 8.5% worldwide for U.S. exports. With such return on investment, it is amazing that more firms and governments have not identified Africa as a target market.

South Africa is identified by the U.S. as a big emerging market. The U.S. government strongly believes that South Africa can become a catalyst for growth to the entire southern African region. U.S. Vice president Al Gore and Executive Deputy President Thabo Mbeki, co-chair the U.S./RSA Bi-national Committee, of which the Business Development Committee is a partner. The BDC consists of six committees composed of senior government officials from each country. Both organizations work to remove business impediments and ensure close bilateral cooperation to support private enterprise. U.S. President Bill Clinton released the Africa Trade and Development Policy report to Congress in conjunction with the February 1997 Trade Mission to five African nations led by Ron Brown. The report encourages African governments to liberalize trade and investment policies within a framework of democratic initiatives, market-based policies *and creation of enabling business environment.* The Plan centers on individual African governments embracing socio-economic reform, regulatory restructuring, and the lowering and leveling of barriers to trade and investment. President Clinton also recently visited six African nations with a large contingent of politicians and business leaders. This has created an incentive to invest in Africa for government as well as the private sector. New technologies such as clean coal technology and renewable energy applications can be exchanged with Africa, creating an energy technology transfer.

Private industry must lead and government must provide the impetus for reforms to spur economic growth. The World Bank report documents a direct correlation between countries that have embarked on major policy reforms and those that have experienced the greatest economic growth. It is the responsibility of government to maintain freedom and accountability to remove constraints on political and economic freedom.

In following this cooperative strategy, the international community will seek out opportunity within African borders.

Table 6 Eskom's Coal Plants

Name of Station	Location	Net capacity of Generator sets MW	Net maximum capacity MW	Net electricity generation GWh	Net maximum power produced MW	Generation load factor %
Coal Fired						
Arnot	**Middleburg, Mpumalanga**	**6 x 350**	**990**	**5,099**	**1,079**	**58.6**
Camden	**Ermelo**	**8 x 200**				
Duhva	**Witbank**	**6 x 600**	**3,450**	**23,173**	**3,492**	**76.5**
Grootvlei	***Balfour***	***6 x 200***				
Hendrina	**Hendrina**	**10 x 200**	**1,900**	**13,068**	**1,895**	**78.3**
Kendal	**Witbank**	**6 x 686**	**3,840**	**22,053**	**3,977**	**65.4**
Komati	**Middleburg, Mpumalanga**	**5 x 100; 4 x 125**				
Kriel	**Bethal**	**6 x 500**	**2,850**	**15,061**	**2,816**	**60.2**
Lethabo	**Sasolburg**	**6 x 618**	**3,558**	**20,607**	**3,526**	**65.9**
Majuba	**Volksrust**	**1 x 657**	**1,224**	**1,916**	**1,027**	**47.4**
Matimba	**Ellisras**	**6 x 665**	**3,690**	**24,737**	**3,683**	**76.3**
Matla	**Bethal**	**6 x 600**	**3,450**	**23,338**	**3,491**	**77**
Tutuka	**Standerton**	**6 x 609**	**3,510**	**14,488**	**3,551**	**47**
Subtotal coal-fired (13)			28,462	163,540		

U.S. Clean Coal Technology Project Demonstrations

Advanced Electric Power Generation

Fluidized Bed Combustion

Pressurized Circulation Fluidized Bed Demonstration Project
Lakeland Department of Electric & Water, Lakeland, Florida

The Tidd Project
Pressurized Fluidized Bed Combustion
The Ohio Power Company, Brilliant, Ohio

The Nucla Circulating Fluidized Bed Project
Atmospheric Fluidized Bed Combustion
Tri-State generation and Transmission Association, Inc., Nucla, Colorado

Advanced Combustion Systems

The Healy Clean Coal Project
Alaska Industrial Development and Export Authority, Healy, Arkansas

The Alaskan Coal-Fired Diesel Project
Arthur D. Little, Inc., Fairbanks, Alaska

The Warren Station Externally Fired Combined Cycle Demonstration Project
Pennsylvania Electric Company, Warren, Pennsylvania

Integrated Gasification Combined Cycle

Pinon Pine IGCC Power Plant
Sierra Pacific Power Company, Reno, Nevada

Tampa Electric IGCC Project
Tampa Electric Company, Tampa, Florida

Wabash River Coal Gasification Repowering Project
Wabash River Coal Gasification Repowering Project Join Venture, West Terre Haute, Indiana

Clean Energy Demonstration Project
Clean Energy Partners, L.P., site to be determined

U.S. Clean Coal Technology Project Demonstrations

Environmental Control Technologies

NOx Control Technologies

Demonstration of Coal Reburning for NOx Control
The Babcock & Wilcox Company, Cassville, Wisconsin

Full-Scale Demonstration of Low-NOx Cell Burner Retrofit
The Babcock & Wilcox Company, Aberdeen, Ohio

Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler
Energy and Environmental Research Corporation, Denver, Colorado

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler
Southern Company Service, Inc., Coosa, Georgia

Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of NOx Emissions
Southern Company Service, Inc., Lynn Haven, Florida

Demonstration of Selective Catalytic Reduction
Southern Company Service, Inc., Pensacola, Florida

Micronized Coal Reburning for NOx Control
NY State Electric & Gas Corporation, Lansing, NY; Eastman Kodak Company, Rochester, NY

Sulfur Dioxide Control Technologies

10-MW Demonstration of Gas Suspension Absorption
Airpol, Inc., West Paducah, Kentucky

Confined Zone Dispersion Flue Gas Desulfurization
Bechtel Corporation, Seward, Pennsylvania

LIFAC Sorbent Injection Desulfurization Demonstration Project
LIFAC – North America, Richmond, Indiana

Advanced Flue Gas Desulfurization Demonstration Project
Pure Air on the Lake L.P., Chesterton, Indiana

Innovative Application of Technology for the CT - 121 FGD Process
Southern Company Service, Inc., Newman, Georgia

Combined SO2/NOx Control Technologies

SNOX Flue Gas Cleaning Demonstration Project
ABB Environmental Systems, Niles, Ohio

LIMB Demonstration Project Extension and Coolside Demonstration
The Babcock & Wilcox Company, Lorian, Ohio

SOx-NOx-Rox-Box Flue Gas Cleanup Demonstration Project
The Babcock & Wilcox Company, Dilles Bottom, Ohio

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection
Energy and Environmental Research, Inc., Springfield/Hennepin, Illinois

The Milliken Clean Coal Technology Demonstration Project
New York State Electric & Gas Corporation, Lansing, New York

Demonstration of the NOXSO SO2/NOx Removal Flue Gas Cleanup System
NOXSO Corporation, Alcoa Warrick Power Station, Hammond, Indiana

Integrated Dry NOx/SO2 Emissions Control System
Public Service Company of Colorado, Denver, Colorado

Coal Preparation Technologies

Development of the Coal Quality Expert
ABB Combustion Engineering, Inc., and CQ, Inc., Pittsburgh, Pennsylvania and Homer City, Pennsylvania

Self-Scrubbing Coal: An Integrated Approach to Clean Air
Custom Coals International, Central City, Pennsylvania

Advanced Coal Conversion Process Demonstration
Rosebud SynCoal Partnership, Colstrip, Montana

U.S. Clean Coal Technology Project Demonstrations

Coal Processing for Clean Fuels

Mild Gasification

ENCOAL Mild Coal Gasification Project
ENCOAL Corporation, Gillette, Wyoming

Indirect Liquefaction

Commercial-Scale Demonstration of the Liquid Phase Methanol Process
Air Products Liquid Phase Conversion Company, L.P., Kingsport, Tennessee

Industrial Applications

Blast Furnace Granulated Coal Injection System Demonstration Project
Bethlehem Steel Corporation, Burns Harbor, Indiana

Clean Power from Integrated Coal/Ore Reduction (COREX)
Centerior Energy Corporation, Vineyard, Utah

Advanced Cyclone Combustion with internal Sulfur, Nitrogen and Ash Control
Coal Tech Corporation, Williamsport, Pennsylvania

Cement Kiln Flue Gas Recovery Scrubber
Passamaquoddy Technology Limited Partnership, Thomaston, Maine

FOSSIL FUEL POWER INDUSTRY IN RUSSIA

Gurgen G. Olkhovsky
General Director
All-Russian Thermal Engineering Institute
Moscow, Russia

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WAIGAOQIAO THERMAL POWER PROJECT IN SHANGHAI, PRC

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ABSTRACT

The Waigaoqiao Phase II Thermal Power Project is financed by the World Bank. Two units of 1,000 MW class plant will be built. The project is at the design stage. The supercritical technology has been selected for higher efficiency, coal saving, and emission reduction. In addition, "Bubble Concept" has been introduced in the process and adding desulphurization facilities and measures have been taken to lower emissions of dust, waste water, and No_x to protect the environment.

Ladies and gentlemen,

Good morning. I am very glad to be given this opportunity to introduce Shanghai Waigaoqiao Phase II Project. The Shanghai Waigaoqiao Power Plant is located in the Pudong New Area of Shanghai Municipality, People's Republic of China, at the south bank of Yangtze River Mouth, 20 km from the city proper. The total installed capacity as planned is 5,200 MW, of which Phase I Project with 4 by 300 MW have been completed and put into commercial operation. The remaining space will be able to accommodate 4 units of 1,000 MW.

1. GENERAL SITUATION

During the construction of Phase I Project, Shanghai Municipal Electric Power Company I work with was planning to build two coal-fired supercritical units with the single capacity ranging 900 to 1,000 MW for Phase II project. After very careful studies and analysis, both technically and economically, by our experts and foreign consultants, we decided to implement our plan, which is based on the feasibility study made in 1993 and 1994 by East China Electric Power Design Institute, assisted by Sergeant & Lundy engineers, a US consultant engaged by SMEPC. The feasibility study was reviewed by the World Bank. In March 1997, World Bank officially began due diligence to appraise the Project. The Appraisal Report was discussed within the Bank and the approval was granted by the Executive Board of Directors of the Bank in June 1997.

2. SELECTION OF UNIT TYPE AND EFFICIENCY

We decided to adopt 900 MW or 1,000 MW grade supercritical coal-fired units and we also studies the difference between the availability of subcritical and supercritical unit. The study shows that the availability of supercritical units of earlier times in the States is lower, but if we separate those data into two groups, one is the units of "first generation," the other is the units of "second generation", we simply can find that the "second generation" is considerably improved in terms of availability. Since each boiler manufacturers are improving their equipment at different pace, there is no distinct boundary point between the first and the generation units in terms of designing. The equivalent availability factor (EAF) of lately developed supercritical units is about 0.5 % lower than that of subcritical units, resulting from the longer scheduled shut-down for maintenance, however, the data also indicate that the equivalent forced outage rate (EFOR) of the lately developed supercritical units is lower than that of subcritical units. Forced outage is much more undesirable than scheduled shut-down for maintenance in view of operator. Therefore, the design of subcritical unit is unfavorable. For large units carrying base load, supercritical cycle is usually adopted in order to obtain higher efficiency. The efficiency of units with supercritical cycle is expected to be 3.5 % higher than that of subcritical cycle. Benefited from the economic characteristics of capacity scale, the power consumed by the all the auxiliary facility is not proportionally increased with the capacity of units, so the choice of 900 MW or 1000 MW grade unit can bring about additional 0.3 % increase in efficiency. Since the heat rate of supercritical unit is lower than that of subcritical unit, the corresponding fuel consumption and its cost is 3.5 % lower, and the emission of SO_2 (sulfur dioxide), NO_x and is also decreased at 3.5 %.

The capital investment for supercritical unit is estimated 2 % higher than that for subcritical unit. Higher capital investment for supercritical unit is rewarding on condition it carries base load as the efficiency is increased 3.5%. Based on our estimation, the coal consumption of supercritical unit is 15 gram/kWh lower than that of subcritical unit and CO_2 emission is reduced accordingly. Our economic analysis shows that cost of electricity will be 0.25 Cent /kWh lower by using supercritical technology compared with subcritical.

3. FUEL FOR PHASE II PROJECT

According to the Project Proposal, Phase II Project will burn, on annual base, 4.8 mn tons of bituminous coal of high quality, which are from Shenfu-Dongsheng coalmine area in northern part of China, the same source of coal supply for Phase I Project. The coal will be transported to sea port by rail, then shipped to the newly built coal wharf of the power plant (total voyage about 800 km). In order to prevent the coal from flying, sprinkling facilities utilizing wash water recycled from the coal conveying system will be installed. Trees will be planted around the coal yard to limit the wind velocity and reduce coal dust flying. Transfer points, outlets of coal crushers and coal silos will be enclosed and fabric filters will be installed to collect possible flying dust.

The specifications of design coal and check coal for Waigaoqiao Phase II Project is determined according to the coal quality specifications in the Letter of Intent for coal supply and the quality information of the coal actually supplied for Phase I project, the test results of coal samples have been analyzed, and the desgin coal is defined to have an ash content of 12 % and a sulfur content of 0.43 %.

4. ENVIRONMENTAL PROTECTION

The Outlines of Environmental Impact Assessment was reviewed and passed by the Shanghai Municipal Environmental Protection Agency and the National Environmental Protection Agency on May 5, 1994. Based on this Outlines, we prepared the Environmental Impact Assessment Report. In March 1996, being reviewed by the Ministry of Electricity, the Environmental Impact Assessment Report was approved by the National Environmental Protection Agency.

a. Air Quality

Shanghai Municipal Environmental Protection Bureau has already been *monitoring the overall air quality, including parameters of* SO_2, NO_x and TSP (total suspended particles) of Waigaoqiao Power Plant area. The impact on the air quality from Phase I, Phase II and Phase III Projects, except for the pollution from other sources, will be lower than that specified by the Shanghai Standard. Even taking other sources into consideration, the annual average impact of SO_2 will be still lower than that specified by the Shanghai Standard. The predicted SO_2 impact will be lower than that stipulated in the present World Bank Guidelines

High efficient low NO_x burners will be adopted in supercritical boilers for Phase II Project, and the efficiency of electrostatic precipitators (ESP) will be more than 99.7 %. Within the specifications of design coal, the dust concentration will not exceed 100 mg/Nm^3 under any operational conditions when 10% of electric fields is out of service.

b. Application of "Bubble Concept" for SO_2 Emissions in Shanghai Municipality

Shanghai Municipal Environmental protection Bureau has promulgated a new regulation, which requires installation of flue gas desulfurization (FGD) facilities in all coal- fired projects, including greenfield, renovation and expansion power projects. The predicated SO_2 emission of Waigaoqiao Phase II Project is within the limit stipulated by the Shanghai Standard and the World Bank Guidelines for the sulfur content of design coal is only 0.43%. So Shanghai Municipal Electric Power Company is granted permission by the Shanghai Municipal Government to introduce the "bubble concept" into this Project, that is, to add FGD facilities in Shidongkou Power Plant, which is an existing power plant burning coal with sulfur content of 1.8 %, instead of in Waigaoqiao Phase II Project, and to offset the SO_2 emissions created by the new Project. However, the space for FGD *facilities in* Waigaoqiao *Phase II Project is reserved for future possible installation* when the environmental protection regulation becomes more strict.

According to the World Bank's requirements on introducing the "Bubble Concept," Shanghai Municipal Electric Power Company prepared a feasibility study on the results achieved through adding FGD facilities to 2 units with capacity of 300 MW each of Shanghai Shidongkou Power Plant instead of Waigaoqiao Phase II Project. The calculation shows that both annual average and daily SO_2 concentration will be lowered. Installing FGD facilities at Shidongkou will reduce SO_2 concentrations in city proper two times than FGD installation at Waigaoqiao. By introducing "Bubble Concept" into this project, total SO_2 emissions in Shanghai Municipality will not be increased after commissioning of Waigaoqiao Phase II Project, while the project cost can be decreased by 100 million US dollars.

c. Ash Management

The bottom ash will be crushed, and removed by water ejector to the slag pond, then pumped to dewatering bin and finally to slag yard. The slag yard is located at the power plant site on the bank of Yangtze River. Currently, 100% of slag from Phase I Project is utilized as construction material. A dedicated wharf beside the slag yard has been built for slag consumers. The water will be recycled and there is no waste water discharge.

The fly ash will be transported pneumatically from electrostatic precipitators to storage silo then loaded to air tight trucks for consumers as construction material. Currently, all the fly ash from Phase I Project is being utilized, but we still find it's necessary in our design that fly ash to be wetted by 20% of water and transported by conveyor to the ash disposal wharf, from where the fly ash will be barged about 14 km down the Yangtze River to an ash yard. The ash yard is in barren and unpopulated area of which embankment with concrete outer berm is specially prepared. Concrete tiles will be sealed together to form a sealing lining to the wall of the ash yard. The ash yard will be dried through evaporation. If the surface of ash becomes dry enough to form flying dust, rollers and moveable spray facilities will be used to compact the ash yard and prevent dust from flying.

A green belt will be planted around the ash yard to stop the wind. After being filled up, the ash yard will be covered with top soil for farming.

In summary, we regard the environmental protection as top priority, which is fully reflected in Waigaoqiao Phase II Project. We believe this project will serve as a pioneering model in the course of development in China power sector.

Thank you very much for your attention

AHMEDABAD ELECTRICITY COMPANY IGCC PROJECT IN INDIA

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ABSTRACT

This paper reviews the project history, current status, and future plans for Ahmedabad Electricity Company's proposed 135 MW Integrated Gasification Combined Cycle (IGCC) project. This IGCC project will be the first of its kind in the developing world and will provide a critical milestone in the deployment of Clean Coal Technology (CCT) in the international arena. The elements required for successful commercial implementation of this new technology will be address, with conclusions underscoring the importance of the successful integration of all aspects of project development, including project planning, technology development, and project financing through private/public partnerships. These core project development activities, coupled with continued U.S. government support and involvement in building an international market for deploying clean coal power generation technologies, will facilitate the transfer of IGCC technology to this important market.

Ahmedabad Electricity Company (AEC) is one of the oldest and most efficient private utilities in India. AEC has over 84 years of power generation and distribution experience. The company achieves one of the highest plant load factors in the country—80%—compared to a 60-70% average for all of India. With a debt to equity ratio of less than one, AEC is in an excellent position to attract financing for new projects.

AEC is proactive in terns of its environmental obligations. It has taken several steps to utilize indigenous Indian coal for power generation in an environmentally sensitive manner. These steps include research, development, demonstration, and commercialization of processes for fly ash utilization; introduction of clean coal technologies (CCTs) including fluidized bed combustion (FBC), consideration of coal washing, and integrated gasification combined cycle (IGCC); and planting of over 100,000 trees near its ash ponds and generation plants.

Since early 1993, K&M Engineering and Consulting Corporation (K&M) and Ahmedabad Electricity Company (AEC) have worked together to develop a 135 MW IGCC project for installation at AEC's Sabarmati Power Station in Ahmedabad, Gujarat, India. The targeted date for the IGCC plant start-up and commercial operation is 2002.

K&M conducted an in-depth country analysis in mid-1994 to identify potential barriers to the successful deployment of the IGCC technology in India. This analysis addressed strategies for mitigating such barriers and identified two potential sites—one of which was AEC's IGCC project. In late-1994 K&M were authorized by DOE/FETC to conduct prefeasibility studies for these projects, which was completed in February 1996. In July 1996, K&M/USTDA/FETC hosted a visit by AEC officials to participate in a technical and financial evaluation of IGCC demonstration projects in the United States, which facilitated their due diligence investigation of the IGCC technology, and by submission of a proposal to the Industrial Development Bank of India (IDBI) and USAID for preparation of the Detailed Project Report.

Introduction of IGCC technology in India through AEC's Sabamati project is a significant leap towards the state-of-the-art application that will provide much needed new electricity generation capacity with the least environmental impact. The project is the first of its kind in India—and for the developing world. AEC's foresight in adopting this technology will greatly benefit India and serve as a significant demonstration project for other countries.

INTRODUCTION

Since early 1993, K&M Engineering and Consulting Corporation (K&M) and Ahmedabad Electricity Company (AEC) have worked together to develop a 135 MW Integrated Gasification Combined Cycle (IGCC) project for installation at AEC's Sabarmati Power Station in Ahmedabad, Gujarat, India. The targeted date for the IGCC plant start-up and commercial operation is 2002.

K&M is an internationally recognized leader in infrastructure project finance, private project structuring and development, procurement, engineering, and construction management in the energy, telecommunication, and environmental fields. K&M has participated in over 30 power projects, of which 22 are IPPs, in over 25 countries in a variety of roles that has resulted in an excellent understanding of what it takes to successfully implement a project in emerging markets. We address the needs and expectations of each party involved in a power project transaction based on our experience as privatization consultant to host governments and developers, construction manager, financial advisor, owner/investor, project engineer, owner's engineer, and banker's engineer.

K&M's efforts are primarily focused in the international markets of Asia, Latin America, the Middle East and Africa. We have worked closely with multilateral and bilateral development banks to secure funding to support feasibility studies, technology transfer, training and co-financing for pioneering projects in host countries. In 1994, under a contract with the World Bank and USAID, K&M developed guidelines, issued by the World Bank, for private power project structuring and conducting international bidding in developing countries. These guidelines are now utilized throughout the industry.

Since 1991, K&M has provided technical, engineering, market and business development support for advanced clean coal technologies and other program areas to the U.S. Department of Energy's Federal Energy Technology Center (USDOE/FETC), and its predecessor, the Morgantown Energy Technology Center (METC). This experience has resulted in a thorough understanding of the unique requirements of the parties involved in implementing the commercial application of a Clean Coal Technology project in the international market.

AEC has an installed capacity of 510 MW of which 410 is coal-fired. Demand is expected to increase to 600 MW to 670 MW by 2000/2001 and further to 814 MW by 2005/2006.

AEC has well educated, trained, and experienced personnel who can be credited with achieving overall plant load factors of 80% or higher compared to a 60-70% average load factor for all of India. Had AEC been able to secure full natural gas for its 100 MW combined cycle plant, this plant load factor would be even higher.

AEC is in an excellent position to attract financing for new projects. With a debt to equity ratio of less than 1:1, the company not only has sufficient capacity to borrow, but to secure funding through the capital markets or multilateral and international banks for foreign currency loans. The company has an existing capital market track record, is in sound financial position with a good reputation with financial institutions and consumers, which can provide assurance to potential lenders.

PROJECT HISTORY

In April 1993, K&M initiated a study, under contract with USDOE/FETC, to assess market opportunities for deployment of CCTs, specifically advanced power generation technologies, in the U.S. Agency for International Development (USAID) supported countries. After conducting a series of interviews with U.S. government officials, representatives of multilateral banks, and U.S. industry representatives; evaluating power generation capacities, projected power demands, fuel sources, indigenous fuel reserves; and assessing the legal and financial environment of various countries, K&M identified India as a primary market for the deployment of CCT power generation projects.

Following this assessment, K&M conducted a country-specific analysis in mid-1994 to identify potential barriers to the successful development of such CCTs and development of strategies for mitigating such barriers in India. Forty-five individuals from seventeen organizations were interviewed representing financial organizations, independent power producers, equipment manufacturers, research institutions, and India/U.S. government agencies. These interviews indicated that although some questions remained unanswered, participants favored the IGCC technology for future deployment in India. As a matter of fact Tata Energy Research Institute, National Thermal Power Corporation, Ltd., Bharat Heavy Electricals, Ltd. and others had developed plans in the early 1990s for the development of a "home grown" IGCC technology.

Reasons stated in support of IGCC technology included:

- higher energy conversion efficiency,
- lower water requirement,
- lower atmospheric emissions of particulates, acid rain precursors,
and greenhouse gases, particularly carbon dioxide,
- advanced stage of development.

Major reservations concerning the technology, voiced repeatedly, included:

- lack of operational experience with high ash Indian coals,
- high capital costs, and
- while the technical personnel were convinced and accepted that the IGCC technology as a viable option, there remained a need to perform further due diligence which would demonstrate to the highest level decision-makers at the utilities and financial institutions the commercial readiness of the technology.

During a two-week visit to India in mid-1994, a K&M assessment team identified several potential IGCC projects. Upon return and completion of a screening analysis, the team reviewed the advantages and disadvantages of each project, and subsequently recommended two projects—one of which was AEC's IGCC project—to DOE's Office of Fossil Energy and FETC for further study.

In late 1994, K&M was authorized by FETC to conduct prefeasibility studies for these two IGCC projects in India. AEC, at its own cost, provided personnel and support to help gather the necessary information. The prefeasibility study was completed in February 1996 and a report was distributed among various U.S. government agencies including the U.S. Agency for International Development (USAID), U.S. Trade and Development Agency (USTDA) and financial institutions including the World Bank's International Finance Corporation (IFC) and Global Environmental Facility (GEF).

In July 1996, K&M representatives and AEC managers made a joint presentation to AEC's Board of Directors outlining results of the prefeasibility study and potential approaches for financing such a project. Following this meeting, AEC's board approved a proposal for further evaluation and development of this IGCC project subject to:

- Completion of further due diligence reviews by the technical committee of the board of directors and senior executives of AEC. This due diligence was accomplished by organization and deployment of a technical evaluation visit for members of AEC's technical committee to survey IGCC demonstration projects in the U.S.; interview operating personnel, technology developers and major equipment manufacturers; and assess the suitability and viability of the IGCC technology for the proposed addition to the generating capacity in the company's system.
- Technical review meetings with DOE/FETC officials to solicit their input about the status of IGCC technology and assess the extent of DOE's support and the role that DOE would be willing to play in support of this IGCC project.
- The board of directors directed that AEC minimize pre-development costs as much as possible and submit a proposal to IDBI/USAID for financial support for preparation of a detailed project report (DPR).

In the fall of 1996, K&M and AEC prepared and submitted a funding proposal to IDBI/USAID for preparation of the DPR. K&M obtained underwriting of the technical evaluation visit from USTDA and DOE/FETC. K&M and AEC also contributed to the cost of the technical evaluation visit. Invitations were issued to a team of AEC directors and executives, led by AEC's Chairman to visit the United States.

Working with the World Bank, USTDA, USAID mission in India, DOE/FETC, and private companies (M.W. Kellogg Company, Destec Energy Inc., Texaco Development Corporation, and General Electric Company) arrangements were made for AEC and K&M representatives to visit several DOE/FETC-sponsored IGCC demonstration projects including PSI Energy Inc.'s 252 MW Wabash River Power Plant (winner of Power magazine's 1996 Power Plant Award) in Terre Haute, Indiana, Sierra Pacific's 107 MW Piñon Pine Power Project in Reno, Nevada, and Tampa Electric's 250 MW Polk Power Station in Lakeland, Florida. In addition, meetings were set up with IFC, GEF, USTDA, and FETC officials as well as representatives of technology and equipment suppliers to discuss AEC's proposed IGCC project and requirements for financing.

K&M believes that this focused technical evaluation visit provided the necessary information to convince the AEC team to further pursue development of this IGCC project. We also believe that USTDA and FETC's financial support for this visit, along with their expressed support of IGCC technology in general (and this project in particular) contributed significantly to successful demonstration to the AEC team of the commercial readiness of the IGCC technology.

At the conclusion of this technical evaluation, AEC and K&M signed a memorandum of understanding to pursue the development of this project. In February 1998, USAID, FETC, AEC, and K&M finalized negotiations resulting in USAID and AEC joint funding for the next phase of the project, which is preparation of the DPR. FETC is managing the project for USAID. Having worked together in with the USAID Mission in India since 1982, DOE/FETC is well versed in the Indian power sector.

WHAT WILL IT TAKE?

Determination, endurance, and problem-solving capabilities are three necessary ingredients for successful development of a project. Yet many other fundamental considerations must be addressed in order to achieve financial closing. While this project will be developed and owned by AEC, the project is being carefully structured and all key project agreements are being integrated so that international financing can be obtained. K&M has demonstrated the importance of adhering to sound principles of project finance through its many pioneering IPP projects throughout the world. While conditions may vary from country to country, or project to project, the fundamentals remain constant.

Principles of Sound Project Finance

Project Fundamentals

- Does the project make sense for the buyer, (e.g., is the power really needed; is the offer price-barring subsidies-competitive, etc.)?
- Does the project make use of mature, proven technology?
- How long before the project produces cash flow? How long before completion of the project?
- Are debt coverage ratios ample and able to withstand adverse events?
- Is the buyer of electricity creditworthy?

Project Structuring

- Are project agreements well conceived, balanced, without gaps, and properly interlocked?
- Are the parties best capable of assuming risks doing so?
- Are there adequate maintenance/ overhaul reserves?
- Are there adequate debt service reserves? How quickly are they generated?

Risk Mitigation and Credit Enhancement

- Is every risk properly identified and mitigated?
- Is protection or hedging in place against interest rate fluctuations, or has this issue been budgeted for at all?
- Are interruptions-be they natural disasters or political "force majeure"- properly backstopped? Is cash flow assured during interruptions?
- Are the proper kinds of insurance adequate and obtainable? Is foreign exchange assured or properly protected?
- Is there a date-certain, fixed-price, single responsibility construction contract?
- Are liquidated damages sufficient to cover debt service and revenue loss for failures to meet performance and schedule milestones or to cover the cost of extra fuel necessary to meet efficiency standards?
- Is an experienced operations and maintenance contractor capable of operating the plant in a developing world environment contracted for the project?
- Are guarantees reasonable on both sides, or are they predisposing default?

Source: LatinFinance, Privatization in Latin America, 1995. "Funds and Fundamentals: Securing Sound Financing for New Electric Power Projects," by Michael H. Kappaz, Chairman, K&M Engineering and Consulting Corporation.

K&M's APPROACH

Now, I would like to address some of the barriers to financing a project utilizing a clean coal technology in a new market; some approaches for mitigating these barriers, and why U.S. government support and continued involvement is needed for projects of this type.

In preparing the DPR, K&M will analyze the project from the developer's perspective and address the issues necessary for the developer, in this case AEC, to obtain financing based on the fundamentals of sound project financing. If the answer to a question is negative or a barrier is identified then K&M will develop a strategy to mitigate. And, if a feasible strategy cannot be developed, K&M will recommend that AEC not go forward with the project. However, based on the prefeasibility study and the feedback we have received, K&M is very optimistic and believes that significant international financing can be obtained.

As I will discuss later, it is also clear that without U.S. government support, initial development of this project would not have been possible. This support was a key ingredient in demonstrating that we—the United States—as developers of this IGCC technology, believe that it is ready for commercial use and it should play an important role in future energy projects.

Does the project make sense?

First of all—does the project, addition of a 125-135 MW IGCC project, make sense for AEC? Is the power really needed? Why AEC? Why IGCC? Is the generation cost competitive? In addressing these questions, K&M needed to demonstrate that an IGCC project made sense for AEC then convince AEC and others that the project would have a "reasonable" chance of success.

Is the power really needed?

AEC's current operating license covers an area of about 365 sq Kms (87,968 acres) including the cities of Ahmedabad, the state commerce capital, and Gandinigar, the state political capital. This area has a population of around 5,000,000 and AEC has the exclusive right to generate, transmit and distribute power in this area. AEC is also seeking to expand its area of operation.

AEC is one of the oldest and most efficient private utilities in India. The company started its power generation activities in 1913 with a diesel generation unit. Today, AEC has an installed capacity of 510 MW of which 410 MW is coal-fired. In addition, the company has a 120 MW FBC unit in the planning stages. To meet its peak electric power demand, AEC also imports 165 MW from Gujarat Electricity Board (GEB). Even after start-up of its new 120 MW FBC unit, the projected AEC system demand exceeds its generation capacity. This situation is exacerbated during outages of one or more units. AEC estimates that its customers' demand for power will increase to 670 MW by 2000/2001 and further to 814 MW by 2005/2006.

To meet this projected demand, AEC will need to import additional power from GEB unless its present generation capacity is expanded. Importing power from GEB is not an economic option as the cost of GEB's power generation is higher than AEC's. In addition, based on the load growth projections and power generation expansion plans in Gujarat State, a large capacity deficit is anticipated in the GEB system. This could lead to higher electric power import costs or restricted power supply. Also, because of a limited supply of natural gas and liquid fuels, combined with an abundance of indigenous coal, any additional capacity is anticipated to be coal-fired.

Therefore, the need by AEC to install at least 120-130 MW of additional capacity once every two to three years—will continue throughout the duration of this planning period —and the answer is, YES, the power is needed.

Why AEC's IGCC Project?

After a thorough review of several options and technologies, K&M selected AEC's project from among the various potential candidate projects for the following reasons:

- Market study indicated that IGCC is the technology of choice,
- AEC's in-depth knowledge and understanding of IGCC technology;
- AEC's willingness to support the prefeasibility study and development of the DPR.
- AEC's willingness to go forward with the IGCC technology provided the DPR shows that the project is economical and gasification of Indian coal is viable;
- AEC's excellent financial position;
- Torrent Group and state government support for the project by the way of representatives participation in the project decision making process as members of AEC's board of directors;
- AEC's express desire to reduce water consumption and environmental emissions within their licensed territory;
- State government intent to implement and enforce a more restrictive environmental standards;
- AEC's effective and efficient management, operation, and management of its power generation, transmission, and distribution assets; and

Thus, the initial market assessment resulted in identifying the "technology of the choice" as IGCC because of its potential for reducing water use and emission of greenhouse gasses by using a more efficient power generation technology; the country's great need for power (additional 102,000 MW capacity required by 2007), and a project owner/developer committed to its deployment.

Fuel Source

India is the third largest coal producer in the world and the only major producer in South Asia. Paradoxically, the main production areas are distant from the primary centers of consumption. While reserves appear sufficient, the quality is inferior in terms of ash content as compared to coals available for import from other countries. However, for various reasons, the country and AEC will continue to use coal as the primary fuel for power generation.

One of the keys to the success of this project will be the ability to demonstrate successful operation of the gasifier or gasification island utilizing the proposed indigenous fuel source. A sample of high ash Indian coal must be tested in a commercial scale plant in order to determine its suitability to the IGCC technology and to meet environmental requirements. The Government of India and utility officials have long sought a way to utilize this abundant indigenous fuel source, but have questioned whether such a low-grade coal could be successfully gasified in an environmentally acceptable way.

Preliminary investigation of the suitability of high ash Indian coal appears promising for use with the proposed IGCC configuration. K&M/AEC are confident that the fuel source will prove to be viable. A final determination will be made in the next phase of this project when actual testing will take place.

Environmental Concerns

AEC is proactive in terns of its environmental obligations. It has taken several steps to utilize indigenous Indian coal for power generation in an environmentally sensitive manner. These steps include research, development, demonstration, and commercialization of processes for fly ash utilization; introduction of clean coal technologies (CCTs) including fluidized bed combustion (FBC), consideration of coal washing, and integrated gasification combined cycle (IGCC); and planting of over 100,000 trees near its ash ponds and generation plants.

AEC has aggressively pursued deployment of new technologies as they became available. These new technologies have helped the company to improve generation efficiency and environmental quality at competitive costs. AEC's management concern for the environment has led the company to develop research, demonstration, and commercialization programs for utilization of fly ash in manufactured bricks and other construction materials. AEC's latest venture in this area, in addition to this IGCC project, is evaluation and development of a 500 tonnes per hour coal cleaning project in consultation with USAID. The construction of this coal washing project is anticipated to take 18 months. AEC has also planted over 100,000 trees near its ash pond and generation plants, creating green zones and improving air quality.

Initial assessments contained in the prefeasibility study indicate that the IGCC technology has significant environmental advantages over other coal-fired power generation technologies with the potential to reduce pollution in the city of Ahmedabad.

And, a critical consideration for India, when compared to alternative technologies, IGCC reduces water consumption in coal-fired power generation facilities.

Project Structure

As part of the next phase of work, K&M will assist AEC to structure the proposed IGCC project. During preparation of the DPR, K&M will point out what is needed for the project structuring. For example, we are going to evaluate options under which a contractor with expertise in operating and maintaining the gasifier island will operate the gasifier island and AEC's personnel will operate the power island. K&M will most likely propose that the EPC and O&M contracts be competed, and a turnkey contract with the necessary guarantees and warranties be required.

Risk Mitigation and Credit Enhancement

The prefeasibility study identified several issues that posed barriers to implementation of this project. First, lack of commercial experience with the IGCC technology was an issue. This was primarily due to the technology itself, which was in its infancy. Now, several years later there are highly successful projects operating in the United States that can serve as demonstration venues and provide valuable information based on existing performance records.

Second, as discussed earlier, the proposed high ash Indian coal fuel source was questioned. The proposed commercial scale testing in an IGCC demonstration plants will provide critical information during the next phase of this project to determine viability and compatibility of the fuel source with IGCC technology. Such testing will enable the technology developer to submit evidence to support the required warranties and guarantees, and build confidence that Indian high ash coal can be efficiently gasified. K&M/AEC will work with the selected technology developer, and others, to develop test protocols and duration criteria.

Third, high capital costs to implement the proposed project was identified as a potential barrier. Since completion of the prefeasibility study, financing of such projects have become more viable. The international drive for reduction of greenhouse gases has led developing countries to seek ways to mitigate emission of these gases when implementing new projects. Financial support provided by the GEF of the World Bank will help make projects such as AEC's proposed IGCC power project feasible. K&M and AEC have had several meetings with the IFC/GEF and are encouraged by their interest in this project. And, with the excellent credit rating and good reputation that AEC commands, this project can attract the international project financing necessary to make it a reality.

DOE/FETC Involvement Critical to Project

Working closely with the U.S. private sector, DOE/FETC have provided leadership and guidance for the development of the IGCC technology as well as sponsored the first demonstration projects. FETC's advocacy for the IGCC technology lends an independent, yet credible voice in support of the reliability and viability of this cutting edge technology now ready for export to international markets. Participation in demonstration, testing and training programs facilitated by FETC can provide foreign utility officials and financial institutions with assurance that the technology works. DOE/FETC support and facilitating role will be critical in order to determine the viability of Indian high ash coal as a fuel source through testing in a commercial scale gasification plant. In addition, the selected technology developer and equipment suppliers will be invited to participate and cooperate in the testing program. The U.S. industry participation in this proposed test program will be a testimony to their confidence that this technology is applicable to high ash Indian coal.

PROJECT STATUS

In April 1998, DOE/FETC and the USAID Mission in India approved the Scope of Work proposed by K&M and provided funding to proceed with the DPR. AEC and the USAID Mission in India will share the cost of preparation of the DPR on a 1/3 to 2/3 ratio, respectively and the project will be managed by DOT/FETC for the USAID Mission. Work is expected to commence once AEC's recently appointed new manager assumes his duties and the required advance payment for K&M's work is processed.

FUTURE PLANS

The next step will be to initiate drafting of the Detailed Project Report (DPR) which is expected to be completed within five to six months. The DPR will address the tech-economic analysis, equipment description and a project financing and implementation plan for the proposed IGCC project. Upon AEC and FETC concurrence, the draft DPR will be distributed to selected financial institutions for review, comment and feedback. Specific elements to be addressed in the DPR are as follows:

- Preparation of project technical description and conceptual design.
- Update project capital and operating costs and schedule.
- Verify project financial model (tariff rate, rate of return, etc.) based on updated costs and schedule.
- Prepare Environmental Impact Study Report.
- Finalize selection of the technology supplier. Discussions will be held with suppliers gasification technology to assess their experience with high ash Indian coals, the extent of performance guarantees they provide, etc.
- Develop a financing plan.
- Conduct a series of meetings with financial institutions to appraise them of the project and gauge their level of interest in providing financing for the project.
- Finalize the feasibility report based on the feedback from financial institutions.

As the first step in preparing the DPR, K&M will identify the most viable gasification technology developer and suppliers. This project requires suppliers with specific relevant experience, or suppliers that can clearly demonstrate successful utilization of high ash coal as a fuel source. After identifying the gasification technology developer or supplier, K&M will propose their inclusion as a part of the project team by initiating a memorandum of understanding for facilitating a working relationship between the gasification technology developer or supplier and AEC.

The final DPR, to be completed within seven months, is expected to provide enough information for AEC management to make its final decision on whether to go forward with the IGCC project. The prime objective of the DPR is to identify the key financing considerations, based on information gathered. K&M is confident that use of the IGCC technology will be competitive provided that some funding is available from the Global Environmental Facility of the World Bank, or other donors.

High Ash Coal Testing

The next critical element will be testing of the specific high ash Indian coal in a commercial scale project envisioned for the next phase of this project.. We hope that DOE/FETC will play an active role in facilitating arrangements between AEC and the industrial participants in the United States for testing and analyzing AEC's coal in a commercial scale plant to determine its suitability to the IGCC technology and environmental considerations. In order to promote technology transfer and provide training opportunities for AEC personnel, key managers and engineers will be on hand to witness any testing conducted. Although AEC personnel will not actually operate the gasifier (a responsibility of the supplier), they will need to understand operational procedures.

CONCLUSION

Introduction of IGCC technology in India through AEC's Sabarmati project is a significant leap towards the state-of-the-art application that will provide much needed new electricity generation capacity with the least environmental impact. The project is the first of its kind in India—and for the developing world. AEC's foresight in adopting this technology will greatly benefit India and serve as a significant demonstration project for other countries.

The support and commitment to this important project by the U.S. Department of Energy/Federal Energy Technology Center, the U.S. Agency for International Development Mission in India, and the U.S. Trade and Development Administration is greatly appreciated and has helped pave the way toward bringing this new IGCC technology to the forefront in India. Their continued involvement and support as the project moves toward financial close, construction and operation will have tremendous impact on the success of this project.

Seival Project

Roberto Faria
Copelmi Mineração S.A

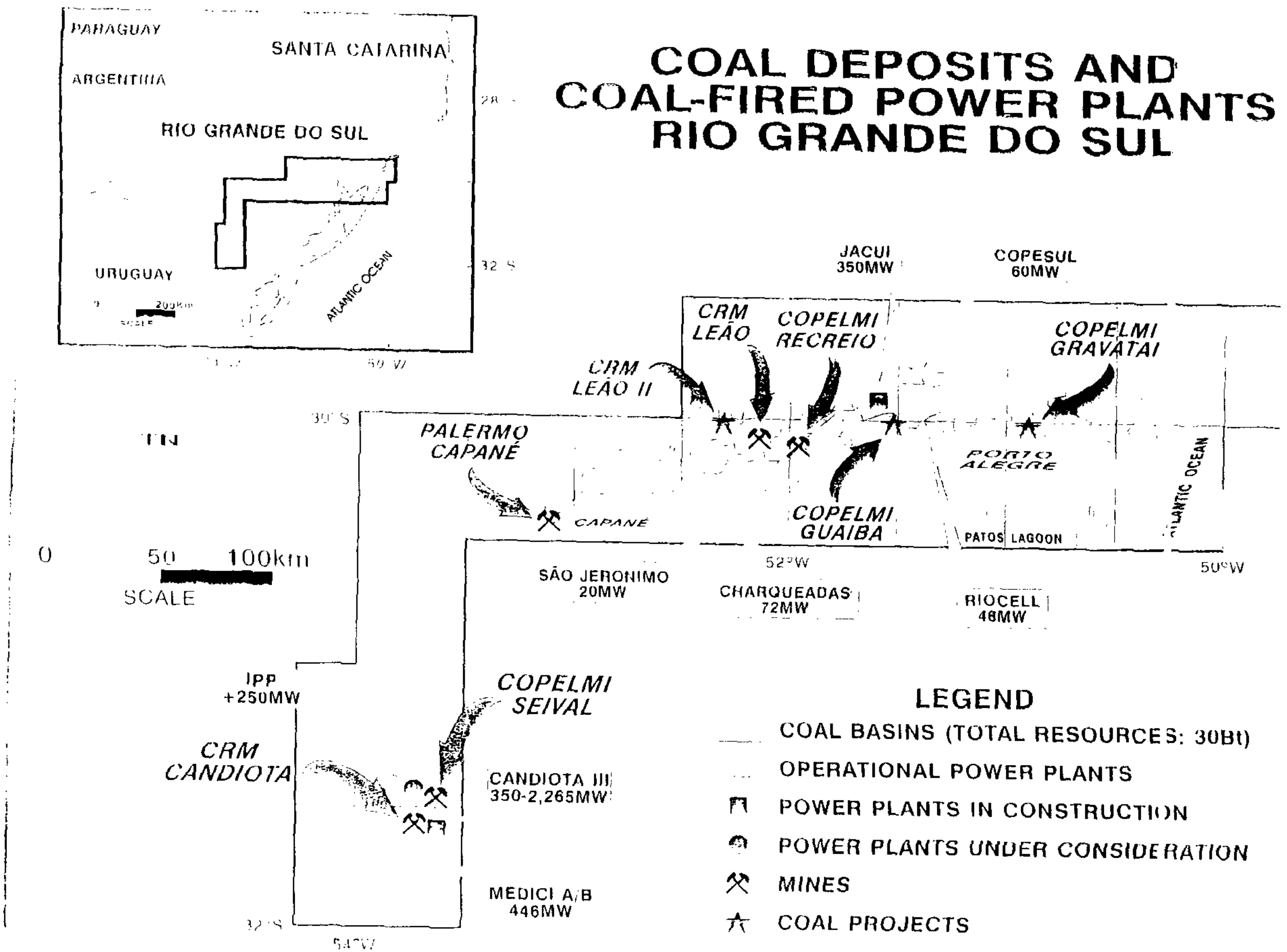
Copelmi

More than 100 years of coal mining

- 1883 Start-up of Arroio dos Ratos mine
- 1889 Start-up of A.Ratos railway (CEFMSJ)
- 1936 CADEM Consortium : A Ratos + Butiá
- 1941 Merger A Ratos + Butiá mines
- 1958 Start-up of Charqueadas Mine Mouth Power Station complex. First IPP Project in Brazil
- 1994 Leasing of Seival property from CNMC
- 1996 40% equity acquired by Rio Tinto

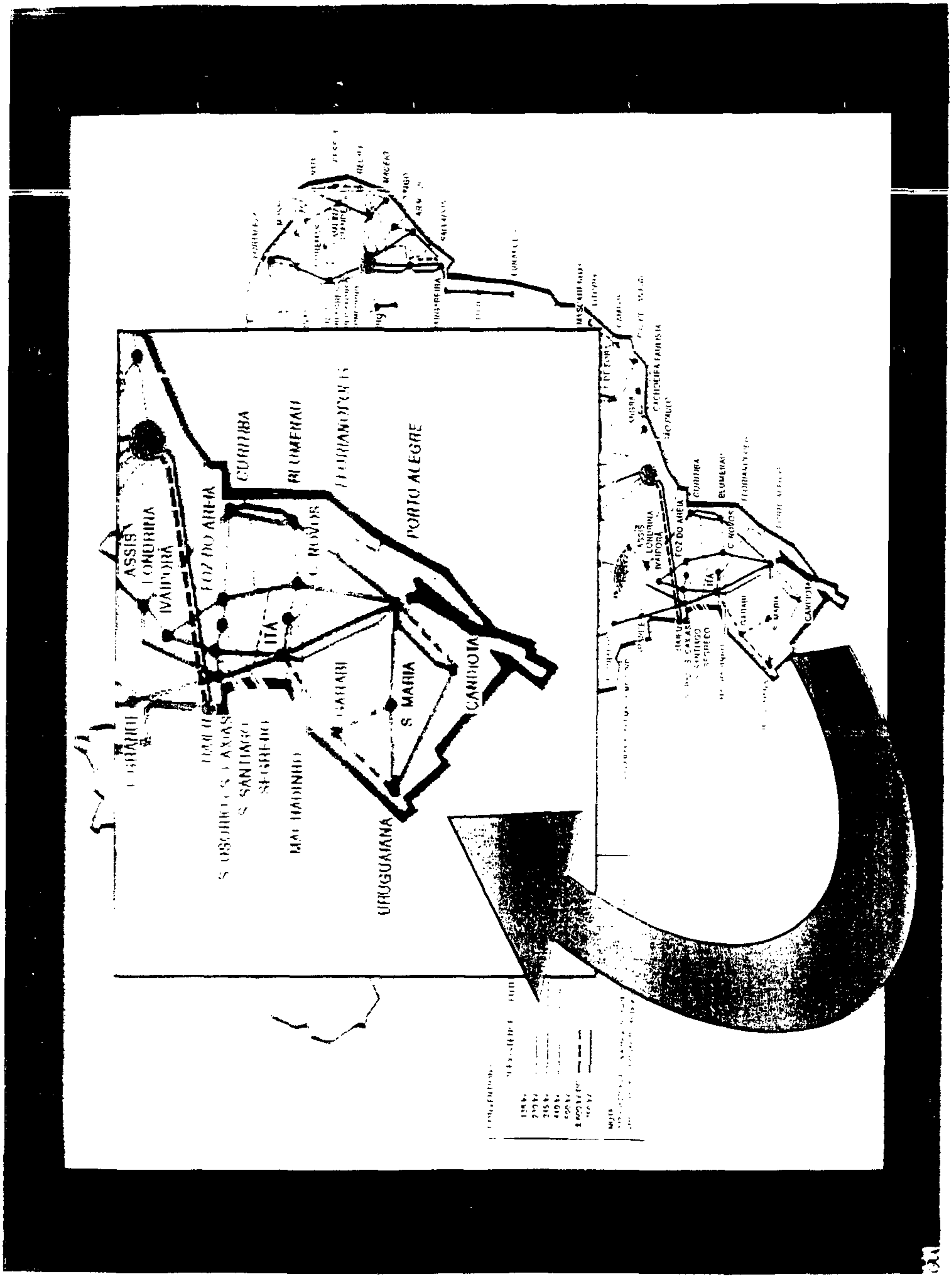
Copelmi Coal Reserves

- TOTAL 2.185, 0 Mt
- Open Pit 485,0 Mt
- Underground 1.700,0 Mt

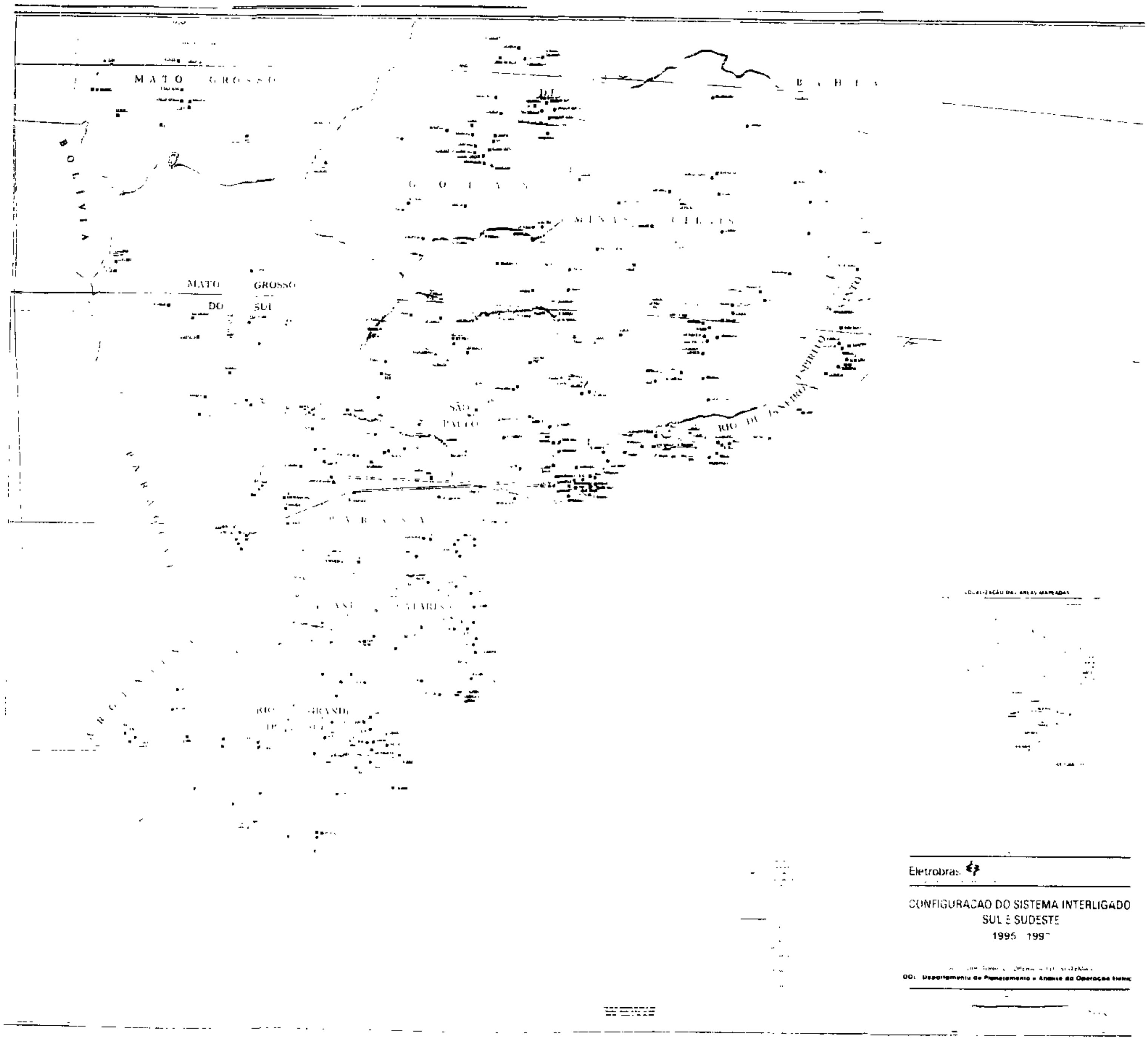

COAL DEPOSITS AND
COAL-FIRED POWER PLANTS
RIO GRANDE DO SUL
PARAGUAY
SANTA CATARINA
ARGENTINA
RIO GRANDE DO SUL
URUGUAY
ATLANTIC OCEAN
SCALE
CRM
LEÃO
COPELMI
RECREIO
COPELMI
GRAVATAI
CRM
LEÃO II
PALERMO
CAPANÉ
CAPANÉ
PORTO
ALEGRE
ATLANTIC OCEAN
COPELMI
GUAIBA
PATOS LAGOON
JACUI
350MW
COPESUL
60MW
30°S
32°S
52°W
50°W
54°W
0 50 100km
SCALE
SÃO JERONIMO
20MW
CHARQUEADAS
72MW
RIOCELL
46MW
IPP
+250MW
COPELMI
SEIVAL
CRM
CANDIOTA
CANDIOTA III
350-2,265MW
MEDICI A/B
446MW
LEGEND
COAL BASINS (TOTAL RESOURCES: 30Bt)
OPERATIONAL POWER PLANTS
POWER PLANTS IN CONSTRUCTION
POWER PLANTS UNDER CONSIDERATION
MINES
COAL PROJECTS

Seival Mine

- **1994 Copelmi leased the mineral rights for 25 years from CNMC. The initial idea was to develop a 125 MW coal-fired power plant, in order to supply energy for the consortium.**
- **1996 Copelmi obtained from DNAEE an authorization**
- **With the new energy market in Brazil, Copelmi is looking for an IPP to develop a mine-mouth power plant, operating in conjunction with the Seival mine.**
- **Preliminary study indicated a Power Plant with 2 x 250 MW and CFB technology, as the most suitable for the project.**



CURITIBA
BLUMENAU
PORTO ALEGRE
ASSIS
LONDRINA
IVAIPORÃ
FOZ DO AREIA
ITÁ
GARABI
S. MARIA
CANDIOTA
URUGUAIANA
S. SANTIAGO

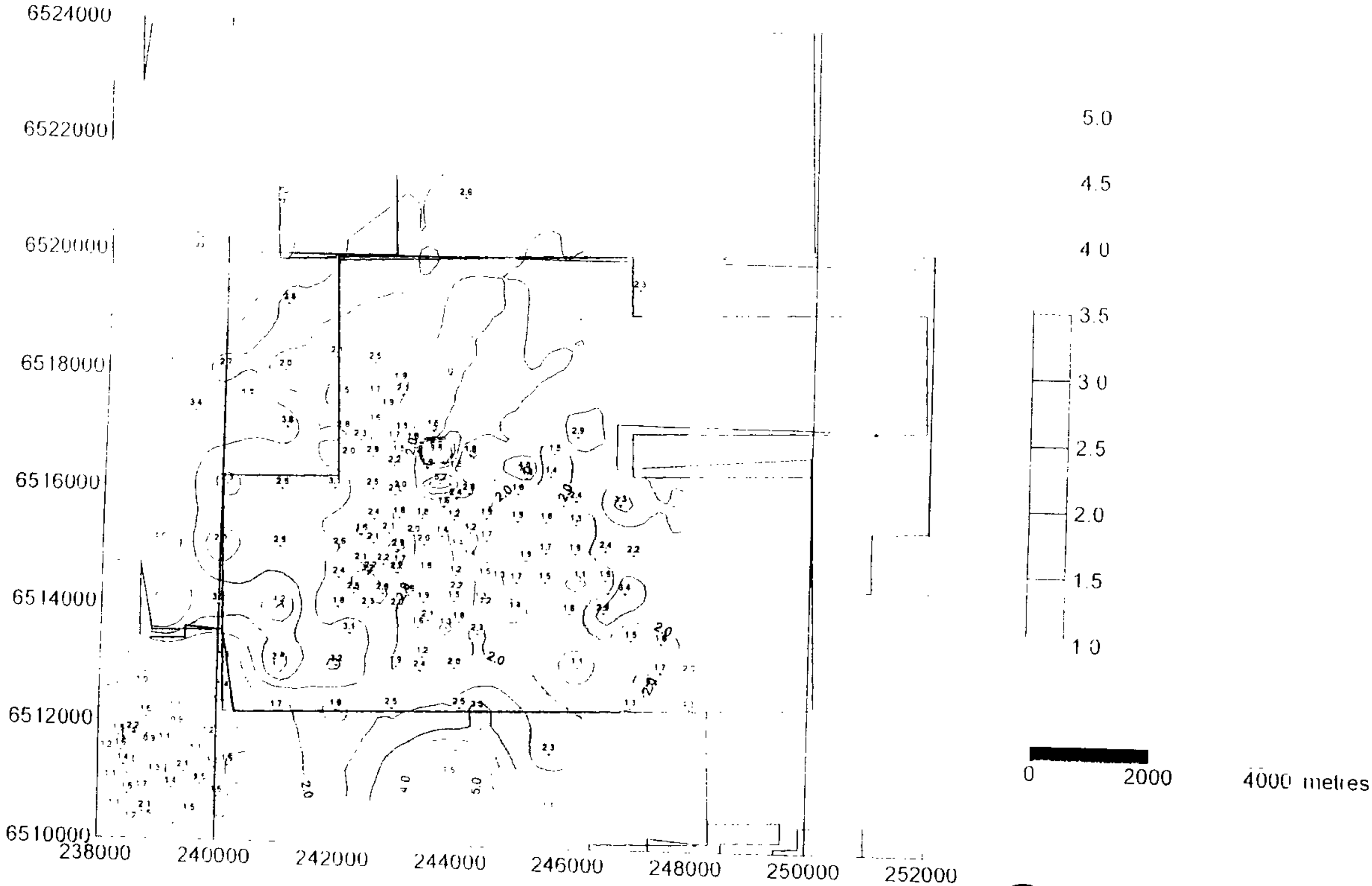

MATO GROSSO
BOLIVIA
MATO GROSSO
DO SUL
Eletrobras
CONFIGURACAO DO SISTEMA INTERLIGADO
SUL E SUDESTE
1995 199?

USTDA - Seival Power Plant Feasibility Study

- November 97- Signed Grant Agreement US$ 470.000.000

- April 15 - **Winner**: Parsons with Taylor DeJongh and Main Engenharia.

- February 99 - Final Report.



Seival Project

stripping ratio bcm/t coal

all seams >0.5m

Energy Demand in Brazil

- **Additional 3.5 GW per year**

- Hydro
- Natural Gas
- Coal

UKRAINE - OPPORTUNITY FOR SALES OF CCT EQUIPMENT

Dr. Victor Gorokhov
Manager, International Projects
Science Applications International Corporation
McLean, Virginia, USA

Ukraine with its large bituminous coal and anthracite reserves and lack of fuel oil and natural gas definitely is a country of interest for implementation of Clean Coal technologies (CCT) and for sales of CCT equipment. In 1994 the US Agency for International Development agreed to sponsor a cooperative U.S./Ukrainian coal-fired power plant upgrade project. A special Ukrainian Clean Coal Task Force was organized with participation of the U.S. Department of Energy (Office of Fossil Energy), the Ukrainian Ministry of Power and Electrification (Minenergo) and the Ukrainian National Academy of Sciences. Original goal for the Task Force was to conduct a feasibility study for upgrading a Ukrainian anthracite-fired power plant, Luganskaya GRES, located in the eastern region of Ukraine. Carrying out of this project coincided with tremendous restructuring in Ukraine's power sector. This restructuring includes transition toward the free energy market, privatization of energy generating and distribution entities, and forthcoming modernization of power plants. Therefore, by the end of the program the initial goal of the Task Force had been broadened to include such matters as evaluation of roles of local and national governments in power plant modernization, international and local investment opportunities and others. As a result, the final conference which was held on April 21-23 of 1998 in Kiev, "Ukraine/U.S. Joint Conference on Ukraine Clean Coal Power Plant Upgrade Opportunities," became an international forum which outlined potential ways for upgrading the entire Ukrainian thermal plant inventory with use of the Luganskaya plant modernization project as a case study. Topics discussed on the conference include:

Role of National Governments in Promoting Changes in Power Industries. This session included presentations by the Deputy Minister of Minenergo of Ukraine, the Assistant Secretary for Fossil Energy, U.S. DOE, the Deputy Minister for Coal Ministry of Ukraine, and representatives of the World Bank and U.S. Agency for International Development. The presentations described status of the energy sector in Ukraine, major results of the U.S. Clean Coal Technology Program, and support provided by the World Bank and U.S. AID to further reforms in the Ukrainian power sector.

Role of the Oblast Government and Power Distribution Companies in Promoting the Power Sector of Ukraine was described in presentations made by the Ukrainian National and regional dispatch centers and Lugansk Oblast administration.

Investment Opportunities in Ukrainian Regional Generating Companies were described in presentations made by all four thermal Ukrainian GENCOs. These reports included description of the current condition of the power generating equipment, proposed modernization and upgrade of fossil power plants, and requirements and options for the financing of such projects.

Power Plant Upgrade at Lugansk GRES: Results of Minenergo/US DOE Clean Coal Technologies Task Force – Case Study. The central session of the conference included presentations on results of a comprehensive evaluation including:

- the feasibility study of the Lugansk GRES modernization project with rehabilitation of one of the existing PC 200 MWe units and construction of a 125 MWe CFB unit consisting of two 62.5 MWe CFB boilers and one 125 MWe steam turbogenerator;

- financial/economic analyses of developed options;

- fuel sourcing opportunities for Ukrainian anthracite power plants (PC and CFB), describing reserves, quality and combustion characteristics of ROM anthracite and coal fuel derived from coal mining and beneficiation wastes;

- other alternatives for power supply of the Lugansk region.

Role of International Financial Institutions and Technical Organizations. This session was dedicated to a discussion of some opportunities to finance Ukrainian power plant modernization projects using international financial institutions, such as the World Bank and the US Export-Import Bank, and IPP companies. Several international power plant design and management companies, such as Foster Wheeler, AES Corporation and ABB, expressed definite interest in participation in upgrade, financing and purchasing power generation and distribution enterprises in Ukraine.

STATUS OF THE POWER SECTOR IN UKRAINE.

The power sector of Ukraine consists of 52.0 million kW of installed capacity, including 31.8 million kW (61%) installed on 14 thermal power plants (104 units), 12.8 million kW (25%) installed on 5 nuclear power plants (15 units), and 4.7 million kW (9%) installed on hydro power plants. The rest (5%) is installed on industrial power plants. All these plants are connected in one power system with more than 1 million km of electrical network with voltage 0.4 to 750 kV, and nearly 3,000 km of central heating systems network.

A major part of the existing fossil units community is represented by 104 sub- and supercritical units with the capacity from 150 MWe to 800 MWe. About 80% of these units have exceeded their design life (100,000 hr). Designed and installed in the period from 1959 to 1975, these units do not respond to current economic and ecological requirements and should be rehabilitated or replaced.

Annual fuel consumption on fossil power plants is 30 to 35 million tonnes of coal, thirteen to 15 billion m^3 of natural gas, and 3 to 4 million tonnes of fuel oil. Ukraine has sufficient geological reserves of anthracite to provide sufficient fuel supply for thermal power plants for not less than 225-250 years. Availability of operating coal preparation plants in Ukraine allows treating of up to 50 million tonnes of anthracite per year. But because of aged equipment and financial problems in both coal mining and coal processing industries, local bituminous coal and anthracite share in the fuel balance is only 35% to 40%. As a result of mines depletion and mining equipment aging and deterioration, currently mined anthracite has about 35 to 40% ash content and lower calorific value in the range of 7500 to 7800 Btu/lb. Thermal power plants are usually supplied with run-of-mine anthracite rather than with washed coal. Low quality of anthracite and deterioration of boiler equipment requires co-firing of a significant amount of supplemental fuel oil and natural gas (up to 30% of heat input).

The National power industry program outlines development of Ukraine's power sector until the year 2010. This program includes plans for shutdown of the Chernobil nuclear power plant, creating an equivalent capacity by means of rehabilitation of existing thermal power plants (TPP), implementation of new technologies to burn Ukrainian anthracite, with simultaneous improvement of environmental performance, and reduction of use of imported fuel oil and natural gas.

At the same time, a critical economical situation in the industry does not permit financing these plans from the state budget in the near future. Part of necessary funds is planned to be received from different international sources. Current investment projects are:

- Hydro power plant rehabilitation and system management project (World Bank loan 114 million US dollars);
- Power market development project (loan 317 million US dollars, part of the loan is realized for fuel purchase);
- 300 MWe unit at Zmievskaya TPP rehabilitation project (German banks loans 126 million US dollars);
- 175 MWe unit reconstruction project with CFB boiler at Starobeshevskaya TPP (EBRD loan 113 million US dollars).

Because loan investment schemes cannot address all needed capital projects in the power sector and cannot be assumed as a regular way to upgrade the entire power industry, another realistic way to obtain financing necessary for modernization of power generating and distribution facilities is by their privatization, i.e. sale of shares, mostly through tenders. Any legal entity or private investor can participate in tenders independently of his citizenship, but in addition to actual price of shares he is obligated to provide some additional investment for the enterprise modernization. This mechanism was used in privatization of two power supply and distribution companies – "Kirovogradoblenergo" and "Ternopoloblenergo," which sold 20% of their shares. Portfolios of shares from 20% to 45% of 18 other power supply companies are prepared for sale. Four generating companies are ready to sell 24% of their shares portfolio through a foreign financial mediator. Currently the winning bidder for "Donbassenergo" and for "Centroenergo" shares will be announced in April. The set of shares to be sold now is less than 51%, but the conditions of transfer to the winner of additional shares (which are temporarily left as state property) will be included in the terms of the tender. There also is a possibility for sale of the entire enterprise or a part of it to an independent power producer (foreign or local).

ENVIRONMENTAL POLICIES AND STANDARDS

Use of low quality coal with parameters much worse than design fuel (ash content 30 to 40%, sulfur content up to 3%) creates problems with operation of flue gas cleaning equipment. The average efficiency of fly ash removal is 95% for 200 MWe and 300 MWe boilers equipped with ESP. On some boilers ESP efficiency is as low as 92%, and particle collection efficiency may be as low as 88% for boilers with bank cyclones and scrubbers. Boilers are not equipped with NO_X and SO_X removal systems. Current average emissions for the power sector of Ukraine are presented in Table 1.

Table 1. Current Emissions From Ukrainian Thermal Power Plants

Emission	Mg/m^3	lb/Mbtu	Ppm
Ash	750 - 3500	0.61 – 2.85	
SO_2	*1600 - 2900*	1.3 – 2.36	*560 – 1015*
NO_x	110 – 670	0.09 – 0.545	53 – 326

As a result, power generating enterprises are responsible for more than 30% of all hazardous pollutants emitted from stationary sources, including 59% of sulfur oxides, 27% of ash, 12% of nitrogen oxides. Data from the European Economic Commission of UNO indicates that Ukraine is responsible for 7% of total sulfur emissions in Europe. Thirteen main Ukrainian power plants are included in the list of 100 most important sources of sulfur emissions in Europe, and two of them occupy 14th and 15th places in this list.

After Ukraine joined the Council of Europe, it became necessary to make Ukrainian environmental standards and law comparable with that of Western Europe and enforce their implementation by using European and worldwide experience in design of ecological specifications. These new standards are presented in Table 2.

Table 2. New Ukrainian Emission Standards

Fuel	Unit size (MWe)	NO_x limit (mg/m^3)	SO_2 limit (mg/m^3)	Rate of desulfurization
Solid Fuel (6% oxygen)	5 - 100 100 – 500 >500	200	2000 2000 – 400 400	40 for 100 – 167 MWe 40 – 90 for 167 – 500 MWe
Liquid Fuel (3% oxygen)	50 – 300 300 - 500 >500	150	1700 1700 – 400 400	90 90
Natural Gas		100		

The Ministry of Environmental Protection of Ukraine has already developed new approaches to enforcing air pollutant emission standards. Air pollutant emission data must now be reported for thermal power plants. To reach these new standards, modernization of all power generating equipment is necessary. The main attention in the nearest future will be given to design, manufacture and installation of modern fly ash control equipment. Due to a large investment and complexity of operation, the introduction of catalytic nitrogen oxides reduction equipment is not planned in the next decade. The development and broad implementation of modern desulfurization equipment is also doubtful, especially with the lack of space for large scrubbers on existing units.

CURRENT DEVELOPMENTS IN CCT TECHNOLOGIES IN UKRAINE

Nevertheless, some activities in development and introduction of CCT are underway in Ukraine. Several pilot and industrial installations are in the process of construction, testing, and even operation in Ukraine. These are:

- CFB boiler with the capacity of 62.5 MWe was designed for rehabilitation of the Luganskaya TPP. The boiler is designed for firing low quality anthracite and anthracite mining and cleaning waste. The design, based on Babcock and Wilcox CFB technology, was developed by a joint team of Babcock Wilcox and Kharkov Special Design Bureau of Minenergo of Ukraine;

- Repowering of one 200 MWe boiler at Starobeshevskaya TPP with a CFB boiler designed to fire low quality anthracite and coal beneficiation waste is to be financed by EBRD.

- A wet desulfurization plant, supplied by the German company Bischoff, is being implemented on a 200 MWe unit at the Dobrotvorskaya TPP. Construction of this unit with planned 94% sulfur removal efficiency was partially financed by the German Federal Ministry of Environmental Protection. The unit is followed by an ESP of Lurgi design with 99.7% ash removal efficiency.

- Three stage coal burning technology with natural gas reburning is installed at one of the 300 MWe boilers at Ladyzhinskaya TPP. This is a joined international project performed by the personnel of Ladyzhinskaya TPP, the Russian institute VTI, and participation of American organizations EPRI and EER. Currently, another boiler at the same plant is equipped with a micronized coal reburning scheme and is under evaluation;

- One 300 MWe boiler at Zmievskaya TPP will be redesigned for arch fired furnace by Siemens;

- Low NOx burners designed by the Institute of Gas of the National Academy of Sciences of Ukraine are installed on about 100 utility and industrial gas/oil fired boilers;

- In 1998 construction of a pilot plant for flue gas electron-beam scrubbing of SO_2 and NO_x with 100,000 m3/hr capacity will be started on one of the TPP of Donbassenergo.

CONCLUSIONS

1 The forecast for the Ukraine fuel balance indicates that Ukrainian anthracite will be the major type of fuel for the Ukrainian thermal power plants for the near future.

2. Current condition of power generating equipment on most thermal power plants makes necessary its modernization in the near future.

3. New stringent environmental standards from one side and quality of run-of-mine fuel from the other side dictate two approaches for improving Ukrainian anthracite utilization on thermal power plants:
 a) coal cleaning with reduction of ash content to 18% - 20% for combustion in PC boilers. Such an ash content is consistent with the design of most Ukrainian PC boilers currently in operation, and
 b)implementation of new combustion technologies designed to accommodate fuel with high ash and sulfur contents and low volatile matter. These technologies are CFB and arch-fired furnaces.

4. The general situation can be favorable for sale of US CCT's in Ukraine, but sales can be complicated by the following factors:
    - Lack of financing in the Ukrainian power sector;
    - Competition from European companies, which are currently very active in the Ukrainian market.

5. Recommendations for successful sale of US Clean Coal Technologies and equipment:
 - Tailoring of the technology for the specific quality of Ukrainian anthracite;
 - Participation in financing of the project, such as direct investment, BOOT/BOO projects, IPP projects.

OPENING PLENARY SESSION

Clean Coal for the 21st Century:
What Will It Take?

Randy Harris Remarks
Sixth Clean Coal Technology Conference
April 29, 1998

Welcome. I'm Randy Harris, vice president of Sierra Pacific Power's Energy Marketing Group. Sierra Pacific's President Malyn Malquist regrets that he was unable to meet with you himself today.

On behalf of Malyn and Sierra Pacific Power, I'm very happy to welcome the Sixth Clean Coal Technology Conference to Reno.

I want to express my gratitude to the U.S. Department of Energy; the Center for Energy and Economic Development; the National Mining Association; the Electric Power Research Institute; and the Council of Industrial Boiler Owners for this opportunity to say hello today.

For those of you who took the tour of our Piñon Pine Power Plant yesterday, I hope the experience left you with the feeling that you may have glimpsed the future of electric generation in this country.

We're very proud of Piñon Pine, as we are of the confidence and support provided by the U.S. Department of Energy. Without that support, there would be no Piñon Pine today.

Piñon is Sierra's most efficient resource and provides 10 percent of our energy needs. As this project nears completion, the company has every reason to believe that

Piñon will prove to be a cost-effective, clean resource.

However, the future for clean coal technologies in Nevada is uncertain. With industry restructuring and the cost of efficient gas turbines declining (offset by clean air requirements in the future), it's difficult to forecast how a similar project will be built, or who will build it.

~ ~ ~

Reno, Nevada is Sierra Pacific's home base and the largest metropolitan area in our service territory. We can track our history as a company back more than 140 years.

That service territory, by the way, is more than 50,000 square miles in northern Nevada and northeastern California.

How big is 50,000 square miles? You could take six eastern states – Maine, New Hampshire, New Jersey, Rhode Island, Connecticut and Massachusetts – and fit them inside our service territory, with room to spare.

Yet, with all that geography, it was only during the last decade that Nevada's population topped one million people. Today, we're the fastest growing state in the country, and Reno is one of the fastest growing regions.

Despite that growth, the state's density is only 13.5 people per square mile. But, while we may be a small state, we have big ambitions. Going back to our mining roots, northern Nevada has the largest mining operations in North America. We're second in gold deposits only to South Africa.

Nevada is also a land of contrasts, and nowhere is that more evident than in Reno. Thirty minutes away from here is some of the most spectacular Alpine skiing in the world. Squaw Valley USA, home of the 1960 Winter Olympics, is only one of more than a dozen world-class ski resorts that residents and guests enjoy.

As I said, Nevada is a land of contrasts. Travel 30 minutes in the opposite direction from here, and you will encounter some of the most rugged high desert terrain in the world. To the northeast of us is the Black Rock Desert, where some of the world's land speed records have been set.

Last October, a team of Britons took that record supersonic, when their twinjet engine racer blistered the desert floor at more than 760 miles per hour. It was the first time man had broken the sound barrier on land.

Besides being the world's longest race track, this pristine territory is part of the Great Basin Desert. If you're new to northern Nevada, don't let that name fool you. When explorer John C. Fremont coined the name "Great Basin," he assumed this part of Nevada was flat. Nothing could be further from the truth. If you arrived in Reno by air, you probably noticed that the Great Basin is really a series of many basins separated by mountain ranges running north and south.

We enjoy a great quality of life here in Reno. There is a good public-private sector partnership witnessed by the favorable business climate here and throughout the state. Our taxes are low. There is no personal income tax. No inventory tax. No inheritance tax.

One of the main reasons for our area's prosperity is due to an ever-growing tourism and gaming industry. The bulk of state and local revenues comes from the gaming industry.

If you have a little extra time, you might consider exploring the mountains or the desert, the ghost towns, or the glittering lights of downtown.

In fact, I guess we'll be heading out to Virginia City on Friday. Virginia City was Mark Twain's old stomping grounds.

It was the Virginia City area where prospectors searched for gold in the 1860s. They found some, but they also came across a lot of "that damned blue stuff," as they called it. For two years they threw away the "blue stuff," not realizing it was almost pure silver.

Because of the silver, Virginia City became a booming metropolis of 40,000, practically overnight. It dwarfed its largest Western neighbor – San Francisco.

I've been asked to tell you that buses will be leaving this hotel for Virginia City on Friday at about 1:15 p.m., returning at about 6 p.m.

I want to thank you again for the opportunity to welcome you to our city and our state. And I hope this conference is everything you anticipated it would be.

Thank you, and have a lot of fun in Virginia City.

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WHAT WILL IT TAKE TO DEPLOY CLEAN COAL TECHNOLOGY?

Patricia Fry Godley
Assistant Secretary for Fossil Energy
U.S. Department of Energy
Washington, DC, USA

On behalf of the Secretary of Energy, the Department of Energy, and above all, the Office of Fossil Energy, we welcome you to the 6th Annual Clean Coal Technology Conference -- where the finest talent in the "high-tech" world of coal assemble in one place. It is truly an honor to be among you today.

Well, registration at this conference in over 340 and last year at Tampa, final attendance topped out at 318. The fact that, for the sixth year, this conference has attracted so many leaders in the world energy community - producers, equipment manufacturers, consumers, regulators, economists, and others from 22 countries - is testimony to the continuing recognition of the critical role that coal plays in ensuring, secure energy supplies to growing economies worldwide and the increasing challenge - technological, social, political and economic - to using coal without damaging our environment.

This conference continues to thrive because it continues to receive the active support and participation of our cohosts -- the National Mining Association, the Center for Energy and Economic Development, the Council of Industrial Boiler Owners, and the Electric Power Research Institute. These organizations continue to take a leading role in the development of sound energy policies in this country. We have been extremely pleased to work with them in organizing this conference.

There are a lot of people working behind the scenes at a meeting like this. But two people, in particular, are the heart and soul of what makes this conference work -- putting in countless hours over many months. I want to ask Faith Cline and Jean Lerch who, I am very proud to say, are part of the Office of Fossil Energy to raise their hands in the back -- and they deserve a round of applause.

[APPLAUSE]

It seems hard to believe that more than a year has passed since we gathered at Tampa for the 5TH Clean Coal Conference. Since then, we've gone through one transition of leadership at the Department of Energy, and in a few weeks, we will begin another.

People change. And policies change. Since the Tampa conference, the world's community of nations met in Kyoto, and a good number of them have agreed to address head-on the challenge of global climate change. You're going to hear more about that, I suspect, throughout this conference. It is likely to be one of the defining factors in how we address the theme of this conference -- the deployment of clean coal technology.

But despite the changes in personnel and policies in the last year, one thing has remained constant -- the continuing advance of clean coal technology. We continue to make progress -- or perhaps I should say, you in this audience who are responsible for these projects, continue to make progress. Let me give you just a few examples:

Since we gathered in Tampa last year, the Tampa Electric gasification-combined cycle plant continues to accumulate run time. In December, it set achieved 100 percent availability -- an operating record for the plant. It continues to be the lowest cost operating unit on the Tampa Electric grid.

This past March, the Wabash River gasification plant in Terre Haute, Indiana, generated one trillion Btus of synthetic gas. No other single-train coal gasification plant in the world has attained such a production level in a single month.

Since we met last year in Tampa, the Liquid Phase Methanol Clean Coal Project in Kingsport, Tennessee, has started up. And since that occurred last May, the plant has consistently operated at greater than 99 percent availability.

Farther north -- in Alaska -- the Healy Clean Coal plant has been constructed, and startup operations are underway.

We now have the paperwork in place with the Jacksonville Electric Authority to relocate a circulating fluidized bed boiler project to the city, and preserve an important technology option in the Clean Coal Program.

And as many of you are aware, last week, the Department's Under Secretary of Energy Ernie Moniz joined the senior Senator of this State, Senator Harry Reid -- another important member of our appropriations committee – in the first of a series of dedications of the Pi±on Pine Project about 20 miles east of here. I hope that many of you were able to take the tour yesterday and see the newest in this Nation's fleet of 21st century power plants.

So, all in all, it's been a pretty good year for Clean Coal Technology. I'm tempted to recall the phrase once used in a not-too-distant political campaign when the candidate asked "are you better off now than you were four years ago?' And if I asked the clean coal technology industry that question, the answer would be a resounding "yes."

You who are responsible for these projects have done a remarkable job. You are literally reshaping an industry -- and our nation's energy future. And you deserve to give yourself a round of applause.

[APPLAUSE]

So that brings us to the 6th Annual Clean Coal Technology Conference and quite appropriately our theme this year: What will it take to deploy clean coal technologies -- on a large scale -- into U.S. and global energy markets?

I hope that we will use our time here this week not only to reflect on the remarkable advances of the last year, but to look into the future and ask "how do we take maximum advantage of our investments and the technological progress we have made?" "What stands between the bright promise of Piñon Pine, gleaming out there in the Nevada desert, and a host of Pi±on Pines generating clean power for the citizens of India, or China, or for that matter, the 21st century citizens of Nevada, California or Florida?"

That's what we want to talk about today at this session and in the coming sessions. And I hope we can address this matter realistically. We can talk about the promise of clean coal technologies. But we must also recognize the sobering realities of the marketplace, certainly here in the United States, certainly in the near-term.

The U.S. market for Clean Coal Technologies is not expected to be significant until the latter part of the next decade -- 2005, 2010, maybe even later. Currently, most new power projects in the United States will be fired by natural gas, and we have encouraged such diversity in our energy mix.

It is important, however, that we keep making the point to skeptics who don't see new clean coal plants springing up around the country, and immediately jump to the conclusion that $6 billion in public and private investment for clean coal demonstrations has been for naught. Deployment will not occur overnight. Planning for the next fleet of domestic power plants precedes actual construction by a decade or more.

That's why first-of-a-kind plants like Tampa Electric, Wabash, and Piñon Pine are so important -- they are giving utility planners in this country the data they need to make decisions now and in the coming years....decisions that won't materialize for another decade or more, but important decisions just the same. And they demonstrate that we have options in our domestic market - a critical element of a secure energy future and a stable economy.

The overseas market, particularly the developing world, is where we see opportunities for deployment in the near term, as demand for electric power generation continues to grow almost exponentially.

Energy consumption in the developing world is expected to equal the consumption of industrialized nations by 2015 and to double again by 2050.

China -- as we have said at many of these conferences -- could represent an extremely promising market for clean coal technologies. China's Ministry of Electric Power estimates that about 15-20 percent of the country's demand for electricity is not being satisfied. To alleviate shortages, the goal is to increase electric generating capacity to a target level of 290-300 gigawatts by 2000. An estimated 15,000 megawatts of generating capacity will be added each year, at an annual cost of about $15 billion.

China's first law governing electric power generation went into effect in April of 1996. The law encourages foreign investment, including direct investment in power plants through joint ventures or foreign-owned companies. About 20 percent of China's additional capacity is expected to be funded by foreign investment.

India, the countries of Eastern Europe and the Commonwealth of Independent States are also expected to increase significantly the use of coal for power generation.

Yet, we know that emerging markets -- no matter how large and promising -- don't guarantee overnight market acceptance.

We know that customers for new power generation equipment today are likely to adopt conventional coal-fired technologies over advanced clean coal technologies because they are less expensive.

So how do we solve the deployment dilemma? There is no simple or single answer. But we need to continue to examine the changing world energy market and the economic and regulatory policies that will affect the marketplace. Policies do change. Priorities change. And as we enter a new century in which global climate change will likely dominate the world's environmental-- and by extension, its energy -- agenda, there might not be a more opportune time to raise the profile of this issue.

So how do we channel tomorrow's energy investments toward environmentally superior technologies, such as those emerging from our clean coal partnerships?

Obviously, we must talk about incentives and financial mechanisms that will increase the market appeal of Clean Coal Technologies.

Now when I mention "incentives" and "financial mechanisms" in the halls of Congress, the first thing that jumps into a lot of people's minds is a new clean coal subsidy program. And I can tell you, there is no better way to get a door slammed in my face -- or your face -- than to talk about new government subsidies. We may have achieved the strongest economy this country has seen in the last 30 years, but there is not a big appetite in Congress for major new spending programs -- the pending highway bill excluded, of course.

But that doesn't mean we can't consider alternatives to a straight government subsidy program. I believe there are some worth discussing – and I would hope that in the sessions this morning and later in the conference, we could define both the strengths and shortcomings of various alternatives.

"Are there actions that could be taken -- both by the public and private sectors -- that will speed the movement of clean coal technologies over the commercial threshold? And are some actions better than others?"

To stimulate thinking about this, I've thought about deployment incentives in generally three categories. There are certainly others. But let me focus on the three that make sense to me:

One would be conventional types of incentives. Investment tax credits, for example. There's some precedent for that. The Administration has recommended a $3.6 billion tax incentive package in its climate change proposal. That package is oriented toward end-use efficiency and renewable technologies. But could a similar package be structured for clean coal technologies? What would it entail? What types of technology should it encourage? And how many plants for each technology type should it be applied to? Should it be based on efficiency improvements -- the higher the efficiency, the greater the tax credit?

What about a rapid depreciation provision? Would that be sufficient to encourage first-of-a-kind technologies? Or would it have to be considered with other incentives?

These are questions that you can help answer.

A second category of incentives might be termed "environmental incentives." Certain environmental performance targets would be set, and if they are reached, the plant would qualify for something like a production tax credit -- applied, say, for every kilowatt hour generated. This type of incentive is currently used to encourage renewable energy use. How much incentive would be sufficient? Could it be applicable to clean coal technologies? If so, what would be the appropriate pollutants -- conventional pollutants, CO_2, or both? And what would be the appropriate environmental target? How should that be set?

Again, questions that should be considered. We want to know what you think and invite your recommendations.

The third category is probably the farthest away from past practice. I would call it the "risk minimization category."

For example, one possibility might be to establish a Performance or Process Guarantee Funding Pool using both public and private sector funds. It would be an insurance pool for new technologies that would fund unanticipated plant modifications to address surprises that inevitably occur with first-of-a-kind technologies. Once a plant was in operation, the owner would repay the pool out of profits...say, over the first 10 years of operations. In that way, the pool would remain revenue neutral to the funders.

Obviously, a key to this concept is a rigid technical and economic review, much like an insurance company would conduct to determine the amount of coverage to provide. Perhaps, here would be where the government, or a government entity, could provide some third-party technical expertise.

These are ideas I have been thinking about. These are ideas that should be considered not only in the context of the U.S. and not only involving both State and Federal governments but also in the context of international governments and lending institutions and international energy organizations. It is a global matter.

But what I think is significantly less important than what you think? So perhaps over the course of this conference, or after you return to your homes and businesses, you could let me know what you think. Are these approaches that merit further consideration? Or, are there others we should consider?

These are the topics we will deal with extensively over the next few days as well as in the coming years -- all framed by this new family of hardware we call "clean coal technologies" and by the extensive new data we are accumulating on their operation and performance.

A lot of that data is now being compiled for future use by potential customers. And here is another role we think is appropriate for the government. You will see in the exhibit area an online display of the Clean Coal Technology Compendium -- a new effort just getting started that uses the global reach of the Internet to provide clean coal information to interested users throughout the world.

Today, more than ever, information has value. And the information being generated by Piñon Pine, Tampa, Wabash and the other projects in the clean coal family will not only serve as the basis for future deployment...but also as the foundation for future research and development. The technology advances don't not end with the projects you will hear about in the next few days...they only begin.

We have embarked on a path toward an entirely new way of thinking about energy from coal or, for that matter, from any hydrocarbon fuel. We see today's clean coal innovations as the stepping stones toward an entirely new type of energy complex. In our R&D budget for fiscal year 1999, we have tried to capture this concept of the ultimate energy facility with the term "Vision 21."

"Vision 21" is an extension of the projects we are talking about this week. It takes technologies like gasification, liquids synthesis, coal refining, and combines them with new concepts for fuel cells and advanced gas turbines -- creating an energy concept that squeezes every available Btu of energy out of a lump of coal. It is the ultimate, high efficiency fossil fuel-based energy source -- and based largely on our clean coal experience, we believe it is time to begin the final push toward this revolutionary new approach to energy production.

But "Vision 21," by itself, may not be the final answer to coal's long-range future. Efficiency improvements alone -- even the 50 or 60 percent power efficiencies we see for Vision 21 -- may not be enough to meet future climate change constraints.

Ultimately, what makes the difference may be whether we can develop a truly affordable way to capture and sequester carbon. That may, in fact, be the "holy grail" for this industry. It may be the ultimate key to its survival.

Is low-cost carbon sequestration possible? We don't know, but we think it is in this Nation's -- and this industry's -- best interest to begin finding out.

That is why, today, Secretary Peña is announcing the selection of 12 projects, each proposing a potential breakthrough approach for removing greenhouse gases from the ecosystem. The announcement is being posted this morning on our Fossil Energy Web Site, which is on display in the exhibit hall.

Our dollar commitment at this point is relatively small. We are taking just the first exploratory steps. But as Secretary Peña says in the announcement, such processes, if they can be successfully developed, could break the link between the world's use of fossil fuels and concerns over global climate change.

So, the message I want to leave you with this morning is:

Take pride in the substantial accomplishments we have made together. Recognize that the technologies being discussed this week are remarkable advancements that literally will change the face of coal and the coal and power industry.

But also recognize that the journey is nowhere close to being completed. Deployment is the true measure of success. And just as the technologies featured this week are the products of innovation, so too will be the mechanisms that move them over the commercial threshold.

And finally, let me challenge you to look beyond the horizon. What has been done to date only makes what lies ahead more exciting. Are we better off than 4 years ago? You bet we are. And, I can't wait to see what we accomplish in the next four years to ensure that coal will be a clean energy resource helping to deliver energy to improve the lives of people all over the world -- a better world in the 21st century.

On behalf of the Department and our co-hosts, thank you very much for attending our conference this week.

THE IMPORTANCE OF COAL

Robin L. Jones
Vice President, Energy Conversion
EPRI
Palo Alto, California, USA

presented by
George T. Preston
Former Vice President, Generation
EPRI

ABSTRACT

Global energy production, conversion and consumption must be and can be environmentally and economically sustainable. In pursuit of these imperatives, we will move nationally and internationally during the next century to energy technologies featuring improved flexibility, economics, and environmental performance, including reduced emissions of all types.

In this evolution, no single fuel source or set of energy technologies can dominate--because worldwide resources and needs are so diverse--and so, improvements must be sought not only aggressively but broadly. Diversity of technology options is a critical necessity for the near term (2020) as well as the mid term (2050), because technology diversity will allow the use of a variety of fuel sources, can preserve flexibility for meeting realistic emissions targets cost-effectively, and will be the foundation for long-term sustainable solutions.

Coal's important role in an all-inclusive fuel spectrum and in diverse technology options derives from its broad geographic distribution, plentiful supply, and its utility in a variety of commercially available as well as newly demonstrated and potential future breakthrough energy technologies. Because of this flexibility, coal is likely to remain an important, if not dominant, fuel in the global energy mix through at least the middle of the next century and probably well beyond.

I. INTRODUCTION

Speaking on this topic, at this conference, carries a danger of preaching to the already-converted. Many of the obvious messages can be paraphrased as "Aren't we wonderful?" or "Ain't it awful what's happening to us!" In this plenary session I want to convey four messages:

- Technology is a driver of social/economic/political transformation - not a response to it.

- Recognizing the economic and environmental imperatives, energy technologies for the first century of the new millennium must move to increased flexibility, lower cost, and improved environmental performance.

- In the evolution of energy technologies, no single technology and no single fuel source can dominate, because worldwide resources and needs are so diverse; therefore, technology diversity and fuel diversity are vital.

- Coal meets the requirements to be included in a diverse spectrum of fuels - for reasons we've preached to one another at past conferences - and therefore coal technology advances must be supported in the near term in order to preserve today's diversity of choices for the long term.

II. TECHNOLOGY IS A DRIVER OF CHANGE - NOT A RESPONSE TO CHANGE

Restructuring in the U.S. electric utility industry was preceded by several other industries, notably the airlines, telecommunications, banking, natural gas, and interstate freight. All of them - including the electric utility industry - had in common the emergence of technology advances arising out of decades of public and private funded R&D. These technical advances created ways to bypass existing infrastructures and allow a previously rigidly structured and regulated industry to become highly competitive.

III. TECHNOLOGY DIRECTIONS

Now I want to show you some data and offer some observations that support my second message. Table 1 illustrates five global parameters - population, economic product, energy consumption, electricity consumption, and electricity percent of total energy consumption - at 50 year intervals from 1900 to 2100.

- Energy intensity - that is, energy consumption (Row 3 of Table 1) per economic product (Row 2 of Table 1) - has been and will continue to be decreasing.

- The fraction of energy consumed as electricity (Row 5 of Table 1) has been and will continue to be increasing.

These and related data lead to the under-appreciated fact that carbon intensity - carbon conversion per unit energy consumption - has been decreasing at a rate of about 1.3% annually for almost a century and a half (Figure 1).

In order to sustain these desirable trends, energy technologies will be more challenged than ever to provide improved flexibility, economics and environmental performance.

IV. DIVERSITY IS VITAL

As Figure 1 shows, carbon intensity is declining and has been for a century and a half. (The vertical coordinate represents tons of carbon converted to CO2 per Ton of Oil Equivalent total energy consumption.) Without addressing the climate change issue in depth, and intending to be philosophical rather than flippant, I'll only observe the following:

- There is an ongoing global discussion about CO2 emissions.
- *All problems have potential solutions, and all solutions have potential problems.*
- Long timeframes have always been required to effectively address energy-related global environmental concerns, to develop and deploy new generation technology, and to turn over existing generation capital investment (existing fleet) in a fiscally responsible way.

Therefore, we are going to need near- and mid-term solutions as well as long-term solutions. And because in the near- and mid-term we will need to balance global and regional economic development needs against resource limitations and environmental impacts, we must have a full spectrum of fuel sources and technology options. Thus, technology diversity is vital, because it allows diverse fuel sources, cost-effective and flexible environmental performance, and sustainability.

V. COAL PROMOTES DIVERSITY AND GLOBAL SUSTAINABILITY

So why are coal and advanced coal technologies so important in the diversity picture?

Domestic: Early experience in our U.S. electric industry restructuring suggests that we will be seeing a significant loss of generating capacity due to early retirement of nuclear plants and older non-competitive fossil-fired plants. Gas alone is not likely to be able to fill these replacement needs in addition to projected new capacity growth.

International: China and India (notably) will be adding huge amounts of coal-based generation in the next two to three decades.

As part of a long-term coal generation technology Roadmap, the Coal Utilization Research Council, supported by EPRI and other organizations, is developing performance targets that should be driving technology development priorities right now (Table 2). These targets will need to be met if coal technology is to maintain its place in the diversity spectrum of electricity generation. Key targets for year 2020 - not far off as technology implementation time schedules go - are an $800/kW capital cost and greater than 55% thermal efficiency (HHV basis).

For the longer term, we will need to achieve electric generation that is free of CO_2 emissions (not necessarily carbon-free) and to be moving toward electricity and hydrogen as primary energy carriers.

VI. CONCLUSIONS

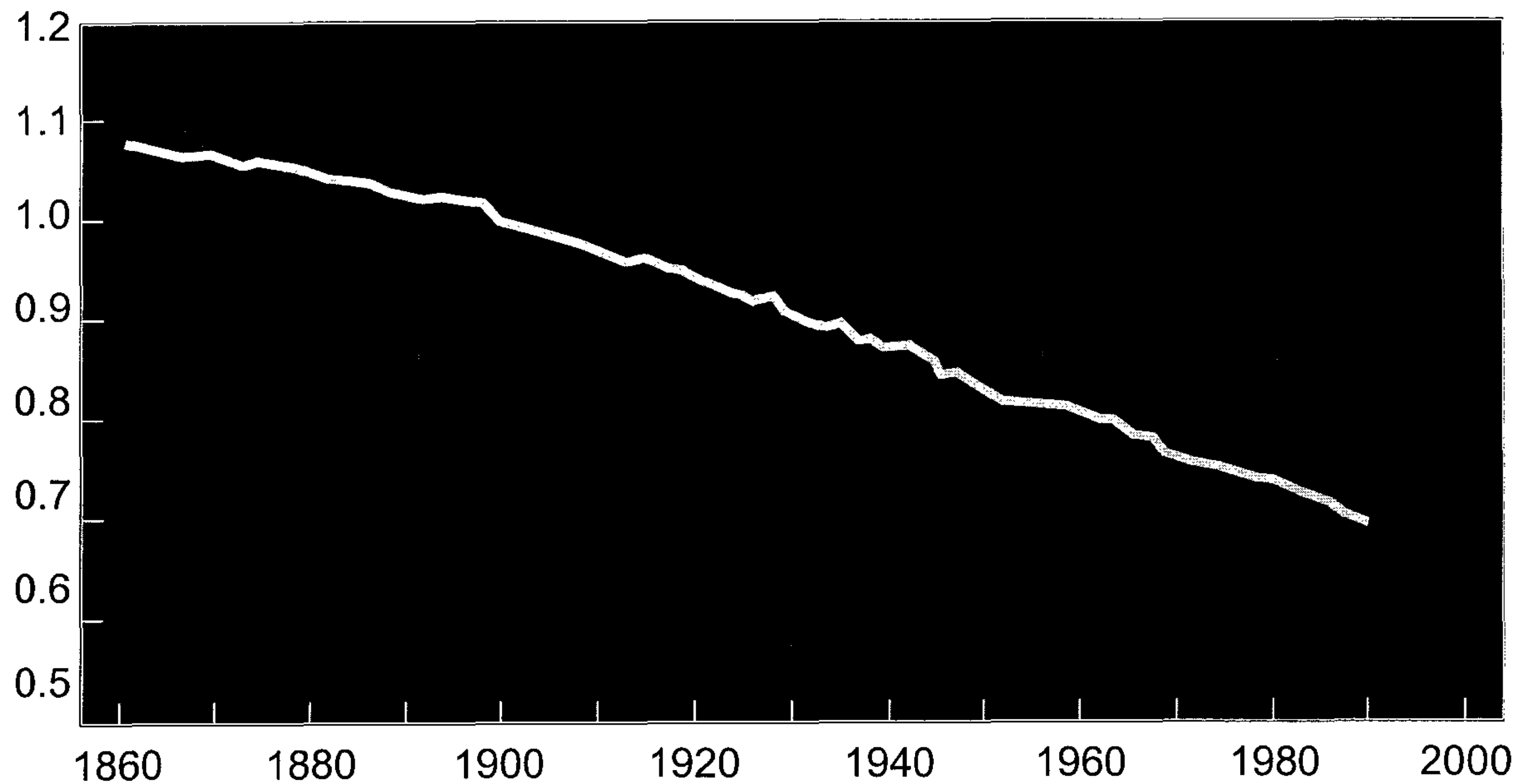
Global development and energy sustainability demand a diverse spectrum of fuels and fuel technologies. Because of coal's worldwide availability, and coal technologies' proven performance and advancement potential, coal is essential to fuel diversity and technology diversity through 2050 and beyond.

And how can we maintain and preserve this diversity that is so important? In the near term, a concerted effort - domestic and international - is required to keep clean coal technology advances moving. To stray from this is to ignore the importance of maintaining diverse options for the future.

Historic and Anticipated Trends

	Actual			Anticipated	
	1900	1950	2000	2050	2100
Global Population	1.7 B	2.5 B	6 B	~10 B	~11 B
Global Economic Product (1990$)	$2T	$8T	$40T	~$140T	~$250T
Global Energy Consumption	40 Q	120 Q	450 Q	~1100 Q	~1350 Q
Global Electricity Consumption (kWh)	-	1T	15T	~45T	~90T
Electricity as % of Global Energy Consumption	~0	7	30	~40	~65

Carbon Intensity of Global Energy Consumption



Source: National Academy of Engineering, 1997

PERFORMANCE TARGETS FOR COAL GENERATION

Performance Target	Today	2010	2020
Capital Cost, $/kW	900-1300	800	800
Efficiency, % HHV	40	45	> 55
SO_2 Removal, %	95	97	99
NO_x, lbs/mmbtu	0.1- 0.3	0.08	0.05
HAPs (Hazardous air pollutants)	define goals	meet goals	meet goals
Waste Utilization, %	30	75	100

Future Worldwide Demand for Coal

Sixth Clean Coal Technology Conference

Presented by
P.J. Adam
Chairman and CEO, Black & Veatch
Chairman, U.S. Energy Association

BLACK & VEATCH LLP

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- Coal Reserves Are an Important Asset in:
  - Asia / Pacific
  - North America
  - Former Soviet Union
- Coal Is Less Important in:
  - Europe
  - Africa and Middle East
  - South and Central America

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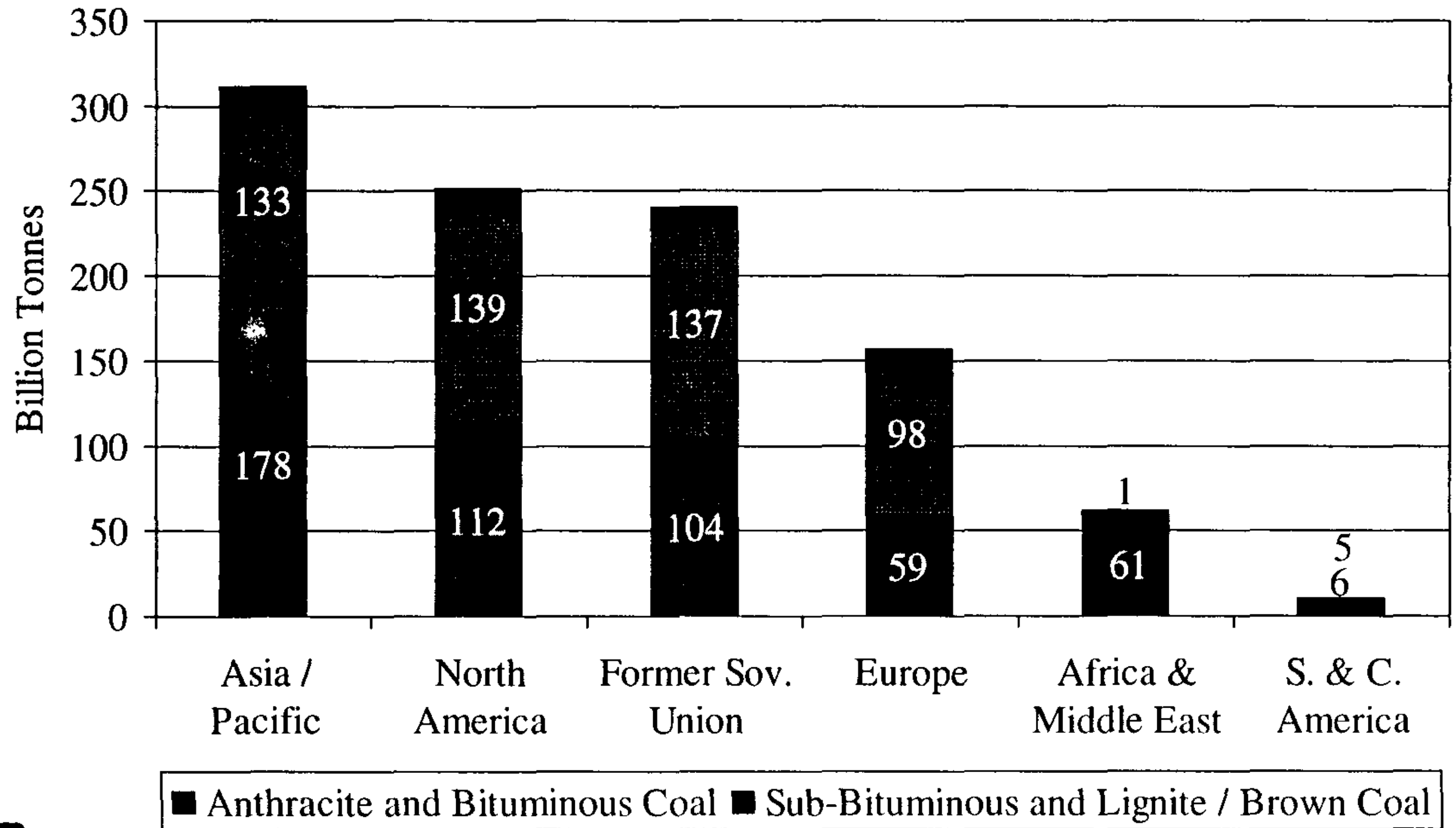
WORLD COAL RESERVES - 1996



Adapted From: BP Statistical Review of World Energy 1997

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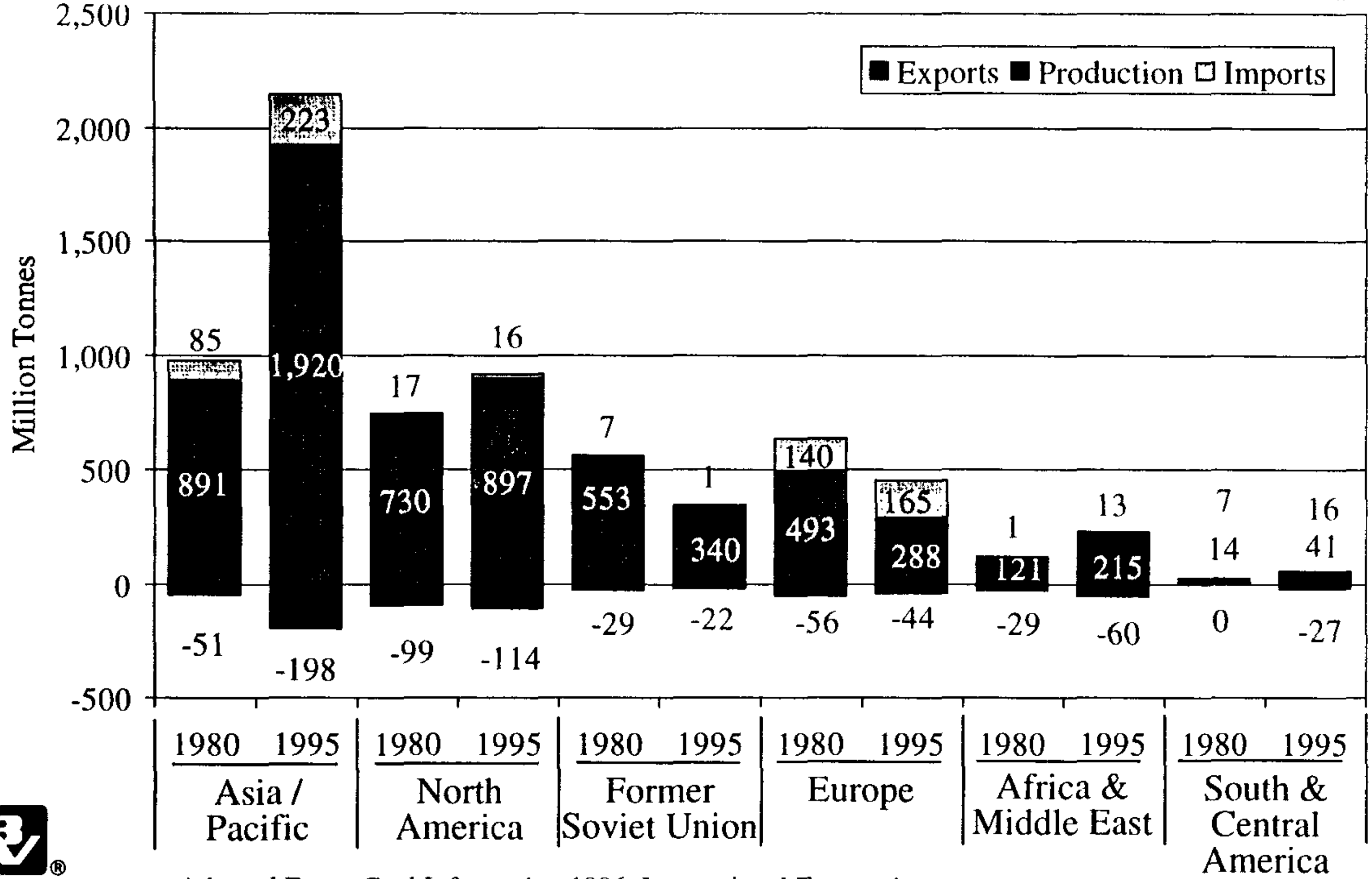
TRENDS IN COAL PRODUCTION AND TRADE (1980 - 1995)



Adapted From: Coal Information 1996, International Energy Agency

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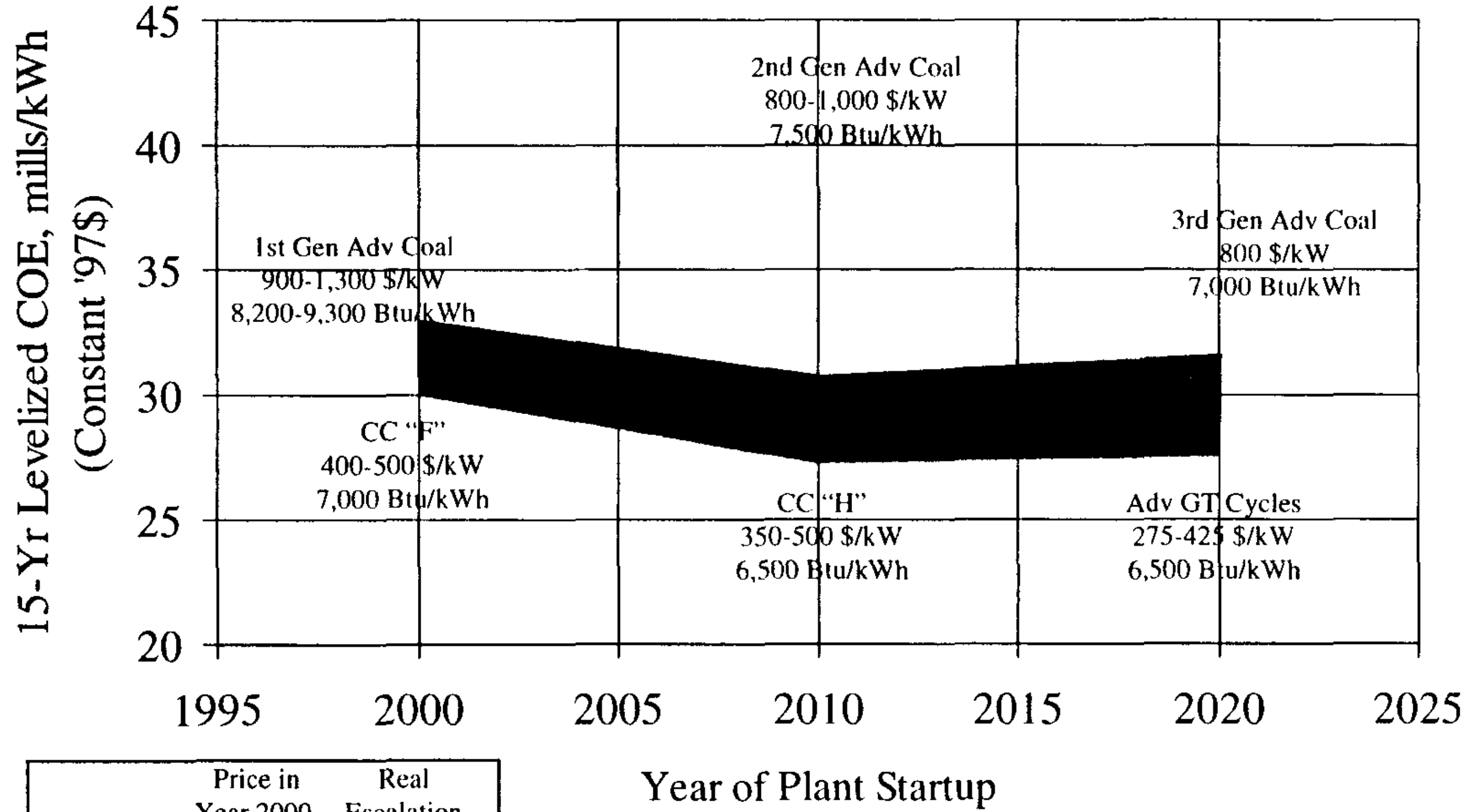
15-YEAR LEVELIZED COST OF ELECTRICITY FOR COAL FIRED VS GAS FIRED POWER TECHNOLOGIES



Fuel	Price in Year 2000 ($/MBtu)	Real Escalation (% / Year)
Coal	1.30	-0.07
Natural Gas	2.25	1.00

Source: Coal Utilization Research Council

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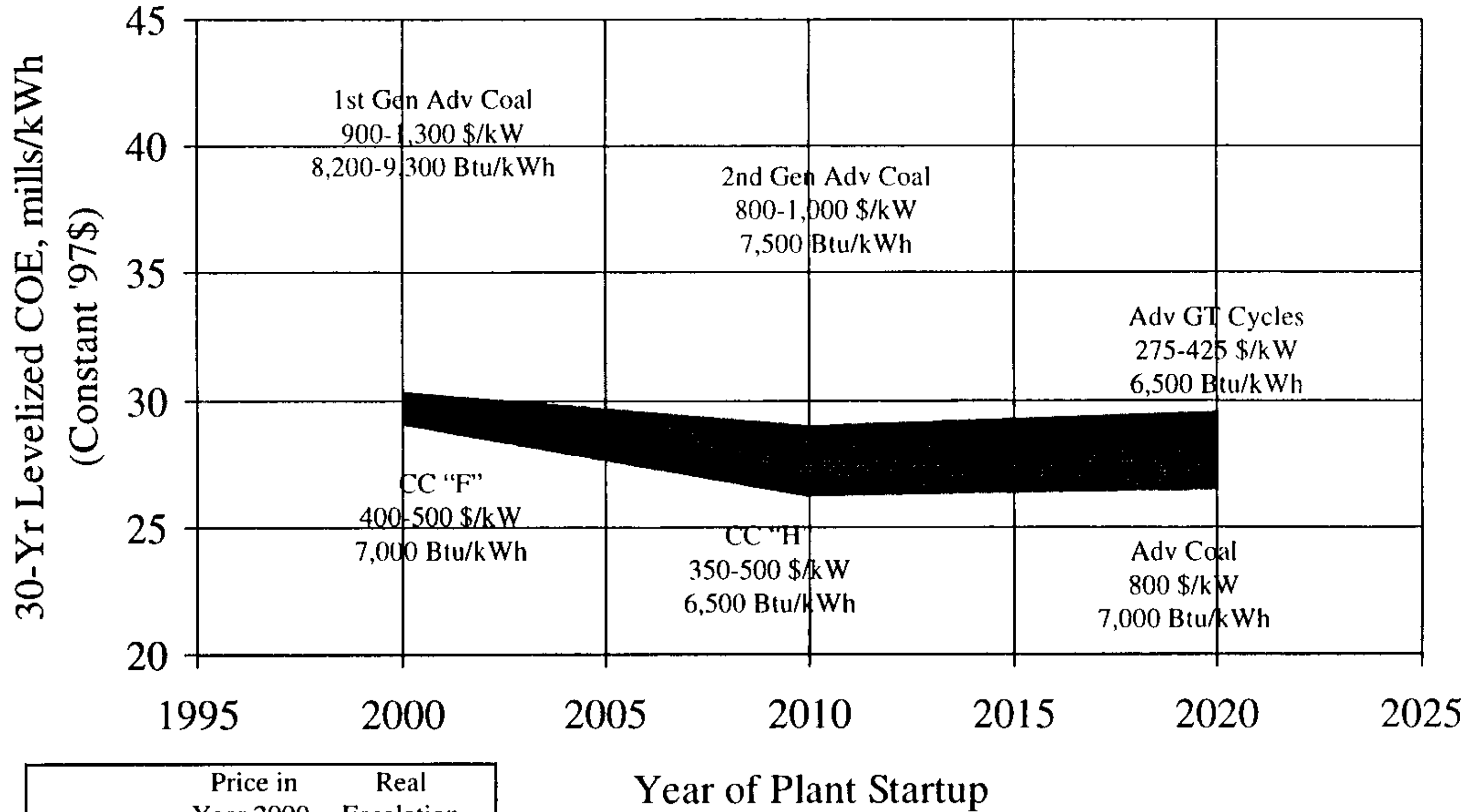
30-YEAR LEVELIZED COST OF ELECTRICITY FOR COAL FIRED VS GAS FIRED POWER TECHNOLOGIES



Fuel	Price in Year 2000 ($/MBtu)	Real Escalation (% / Year)
Coal	1.30	-0.07
Natural Gas	2.25	1.00

Source: Coal Utilization Research Council

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FORECAST

- Coal Production / Consumption Will Continue to Grow Rapidly in Asia / Pacific
  - Very Little Natural Gas Development
  - Rapidly Growing Economies in Spite of Currency Crisis
  - Little Near Term Commitment to CO_2 Control / Reduction
- Coal Production / Consumption Will Be Flat in North America
  - Low Cost Natural Gas Readily Available in Most Regions (But Watch Price Trends)
  - Environmental Pressures on CO_2
- Coal Production / Consumption Will Continue to Decline in Europe and Former Soviet Union
  - Plentiful Natural Gas
  - European Commitment to CO_2 Control / Reduction
  - Lackluster Economy and Mine Safety in FSU

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ADVANCED POWER TECHNOLOGY PERFORMANCE

Advanced Power Technology	First Generation (2000-2010)		Advanced Generation (Post-2010)	
	Fuel-to-Electricity Efficiency	Reductions in CO_2	Fuel-to-Electricity Efficiency	Reductions in CO_2
Low Emission Boiler Systems	42% (HHV)	25%	42% (HHV)	25%
Pressurized Fluidized Bed Combustion	45% (HHV)	27%	50% (HHV)	36%
Integrated Gasification Combined Cycle	45% (HHV)	30%	52% (HHV)	39%
Indirectly Fired Cycle	45% (HHV)	39%	48% (HHV)	40%

Source: Department of Energy

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OPPORTUNITIES FOR IMPROVEMENT
WHERE TO LOOK FOR BTU's

- Turbine
  - New Rotors With Aero Blading
- Boiler
  - Fuel / Air Distribution
  - Air Heater Leakage
- Auxiliaries
  - Variable-Speed Drives
- Controls
  - Retrofit With New System

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EXAMPLES OF PLANT IMPROVEMENT PROJECTS

- EPRI Project #1
  - HP Turbine Seal System Replacement, Air Heater Seal Replacement, FWH Level Monitoring / Control
  - 2-3% Improvement in Efficiency
- EPRI Project #2
  - HP Turbine Chemical Clean, Replace LP Heaters, Performance Monitoring
  - 2-3% Improvement in Efficiency and Capacity by 13%

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CASE STUDY FOR PLANT IMPROVEMENTS

- Planned Improvements
  - New HP-IP Rotor and Diaphragms
  - Generator Rewind and New Excitation
  - New Boiler, Turbine, and BFP Controls
  - GSU Transformer Upgrade
- Results
  - Capacity >10%
  - Efficiency >4%
- Cost Is About $300 / kW Net

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- Clean Coal Technology Will Have High Value in Asia / Pacific
  - Fast Growing Power Production From New Coal Fired Plants
  - Potential for Global CO_2 Emission Trading
- Coal Plant Retrofit for Improved Efficiency Will Have High Value in Industrial World
  - Few New Coal Plants
  - Need to Get More Capacity and Production From Existing Plants
  - Need to Reduce CO_2 Emissions per kWh

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WILD CARD POSSIBILITIES

- Lowering the Cost of LNG on Global Market
  - *Result - More Emphasis on Gas; Less on Coal in Asia / Pacific*
- Need for Rapid Increase in Gas Supply and Transmission Facilities in Industrial Countries Could Drive Significant Price Increase
  - *Result - More Emphasis on Coal; Less on Gas*

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CCTS: PROVIDING FOR UNPRECEDENTED ENVIRONMENTAL CONCERNS

Geoffrey F Morrison
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IEA Coal Research - The Clean Coal Centre
London, UK

ABSTRACT

Emission control regulations for coal-fired power plants have increased in severity over the past ten to fifteen years in response to an increasing awareness of the environmental effects of burning coal. Emissions of sulphur, nitrogen and particulates are now controlled to ever lower limits. Clean Coal Technologies such as CFBC, PFBC and IGCC are being developed to meet these challenges. However, increased efficiency with supercritical steam conditions and recent developments in emission control equipment, mean that pulverised coal combustion (PCC) can also be regarded as a Clean Coal Technology. A study of recent trends in the planning and construction of new coal-fired plants entering service within the OECD region and the factors affecting the choice of technology supports this view. Niche markets for CFBC and PFBC with certain types of low grade coals may encourage their take-up. However, the future for IGCC depends on bringing down the costs to a point where utilities will consider the technology as an alternative to PCC. This is even more true for the developing world. Until then PCC will continue to dominate the market.

Environmental legislation is complex and voluminous. IEA Coal Research maintains a database of emission standards applicable to coal-fired plant which is available on CD-ROM and will shortly be available on the Internet (McConville, 1997). This paper addresses what is happening in terms of environmental legislation worldwide and the implications for Clean Coal Technologies (CCTs).

SO_2 and NO_x emissions became an issue because of the long range effects of these pollutants. Two major strategies have been identified for the control of national emissions: the 'command and control' approach and the 'market orientated' approach. In the European Union the command and control approach has been widely used. The basis of the European Union policy in terms of SO_2 and NO_x emissions is the Directive on the Limitation of Pollutants Emitted by Large Combustion Plants which was approved by the Council of Ministers in 1988. New plants using solid fuel and with an input greater than 500 MWt are required to control:

SO_2 emissions:	below 0.33 lb/MMBtu (400 mg/m^3)
NO_x emissions:	below 0.53 lb/MMBtu (650 mg/m^3)
particulates:	0.03 - 0.05 lb/MMBtu (40 - 65 mg/m^3)

In practice, a number of EU countries such as Sweden and Austria have chosen to enact national standards that are considerably more severe than the EU limits. SO_2 emission limits of 0.16 lb/MMBtu (200 mg/m^3) and below are being introduced. Sweden now requires SO_2 emissions below 0.12 lb/MMBtu (150 mg/m^3) and Portugal 0.08 lb/MMBtu (100 mg/m^3).

NO_x emissions of 0.16 lb/MMBtu (200 mg/m^3) and below are also required in many European countries and elsewhere. Sweden has a limit of 0.11 lb/MMBtu (135 mg/m^3) reducing to 0.07 lb/MMBtu (80 mg/m^3) for plants > 500 MWt.

Particulate emissions may be required to be as low as 0.01 lb/MMBtu (10 mg/m^3), for instance for large coal-fired plant in the vicinity of cities in Japan. This results in a stack with virtually no visible emissions.

In the USA, a more market based approach has been adopted to control SO_2 emissions. Phase I of the CAAA 1990 required 261 generating units, designated affected units, to comply. An additional 174 units are participating under EPA rules for compensating plants. The average SO_2 allowance was set at 2.5 lbSO_2/MMBtu (3075 mg/m^3). For Phase II, which comes into force in the year 2000 approximately 2300 units with capacities of more than 25 MWe will be involved. The average SO_2 emission allowance will be reduced to 1.2 lb/MMBtu (1475 mg/m^3).

NO_x emission limits were also required under Phase I:
0.45 lb/MMBtu for tangentially-fired (554 mg/m^3)
0.50 lb/MMBtu for wall-fired (615 mg/m^3)

The complexities of environmental legislation for coal-fired plant are beyond the scope of this paper. However, the message is clear: environmental legislation is becoming more stringent and only very low emissions of SO_2, NO_x and particulates are now tolerated in environmentally sensitive areas.

What does this mean in terms of Clean Coal Technologies? If we now look at he different technologies available.

Circulating fluidised bed combustion (CFBC)

CFBC boilers have achieved considerable success in relatively small units (~100 MW) exploiting low value or waste fuels. There is relatively little experience with boilers above 100 MWe and none with supercritical units. With increasing unit size, economies of scale tend to cancel CFBC's initial cost advantage as multiple unit CFBC boilers compete with single unit PC installations and the cost of FGD installations benefit from the development of large, single absorber vessels. The largest CFBC boiler in operation is at Gardanne in France at 250 MWe. A 200 MWe CFBC is being built in Korea and two 233 MWe units in Poland. Hence, within the next few years there should be commercial experience with the operation of CFBCs of up to 250 MWe. Designers have expressed confidence that they can be scaled up to 500 - 600 MWe.

CFBCs produce inherently low emissions of SO_2, NO_x and particulates. However, at locations where standards are stringent (SO_2 and NO_x below 0.16 lb/MMBtu (200 mg/m^3)) additional control measures may be needed. Control of sulphur by sorbent injection alone may require unacceptably high Ca/S ratios with corresponding disposal problems. The increased lime content of the bed may increase NO_x emissions. Hence some operators of CFBC boilers have been obliged to fit post combustion emission controls to their plant.

Pressurised fluidised bed combustion (PFBC)

There are a number of operating PFBC plants around the world, mainly based on ABBs P200 unit. Table 1 shows the four operating units at Värtan in Sweden, Escatron in Spain, Tidd in the USA and Wakamatsu in Japan. The table also shows design data for the plants at Karita and Cottbus.

PFBC units benefit from the effects of pressure in enhancing sulphur capture efficiency. At atmospheric pressure $CaCO_3$ (in limestone and dolomite) and $MgCO_3$ (in dolomite) calcine to CaO and MgO respectively. These compounds react with SO_2. Under PFBC conditions $CaCO_3$ does not calcine since the partial pressure in the bed is in excess of the decomposition pressure; only the $MgCO_3$ component in the dolomite calcines. As a result $CaCO_3$ reacts directly with SO_2 to form calcium sulphate. This leads to higher sulphur capture efficiencies at lower Ca/S ratios. Results from PFBC demonstration plants have confirmed sorbents perform better under pressurised conditions.

Whilst NO_x emissions are inherently low from PFBCs because of the relatively low temperatures, stringent emission standards may require the use of flue gas treatment processes such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). At Värtan an SCR plant was installed immediately after the gas turbine to meet the stringent 0.04 lb/MMBtu (50 mg/m^3) emission limit. Ammonia is also injected into the freeboard or cyclones to maximise the SNCR effect. An SCR is also used at the Wakamatsu plant in Japan. Particulates can be controlled by the use of ESPs or fabric filters.

Integrated gasification combined cycle (IGCC)

Most of the current development of IGCC features entrained flow, oxygen blown, slagging gasifiers. The exception is the Pinõn Pine project at Reno which features an air blown Kellog Rust Westinghouse pressurised fluidised bed gasifier. Table 2 lists the major demonstration projects on IGCC. Smaller scale work is in progress in countries such as Japan. Outside the USA and Australia, enthusiasm for this route has waned in the face of the obstacles found. However, IGCC is making more progress for refinery wastes than for coal.

The entrained flow, oxygen blown gasification technology was first used for the preparation of synthesis gas. The sensitivity of the synthesis catalysts to sulphur required the gas to be cleaned to a purity considerably in excess of that required for power generation. For example, syngas would normally be expected to have a total sulphur content of less than 1 ppm.. However, the cost is not negligible. The acid gas removal section of an IGCC plant typically accounts for 10-15% of the capital coast of the plant. However, it is expected that SO_2 emissions from the Puertollano plant will be less than 0.02 lb/MMBtu (25 mg/m^3).

NO_x emissions are determined by the conditions in the combustion turbine. Measured NO_x emissions at Buggenum are below 0.06 lb/MMBtu (70 mg/m^3).

At first sight it would appear that the application of a well proven process, coal gasification, to another well proven process, the generation of electricity using gas as fuel, should be relatively trouble free. However, the economics of IGCC require higher thermal efficiencies than are required for syngas production. This requirement for higher thermal efficiency, at a moderate capital cost, has increased the complexity of the process and has involved a major research and development effort which is continuing.

Pulverised coal combustion (PCC)

Pulverised coal combustion can also be regarded as a Clean Coal Technology. An uncontrolled pulverised coal fired power station burning 2.5% sulphur coal would release flue gas containing about 3.82 lb/MMBtu (4700 mg/m^3) SO_2, 0.65 - 1.63 lb/MMBtu (800-2000 mg/m^3) NO_x and around 6.5 lb/MMBtu (8000 mg/m^3) of dust. To meet emission standards of 0.16 lb/MMBtu (200 mg/m^3) for SO_2 and NO_x and 0.04 lb/MMBtu (50 mg/m^3) for particulates, control equipment on PC fired power plants must reduce emissions of SO_2 by at least 95%, of NO_x by at least 85%, and of particulates by at least 99%. Much has been achieved in recent years in the development of emission control equipment, so much so that flue gas desulphurisation processes can now remove up to 99% SO_2 at reliabilities approaching 100% and at costs which now represent less than 10% of the capital cost of a plant. Selective catalytic reduction (SCR) of NO_x can remove up to 95% of NO_x. Wet particulate removal systems can remove up to 99.9% of dust. It is often forgotten that many of these developments have been achieved under the Clean Coal Program in the USA.

Economics

A recent study by The Clean Coal Centre evaluated costs of various CCTs on a common basis (Scott and Nilsson, 1998). The base assumptions of this work relate broadly to a plant using thermal coal of international quality and operating under the environmental constraints now common in the OECD countries. In the case of a PC plant for example, efficient electrostatic precipitator (ESP), FGD and SCR units would be required to achieve SO_2 and NO_x emissions of less than 0.16 lb/MMBtu (200 mg/m^3) and particulate emissions of less than 0.04 lb/MMBtu (50 mg/m^3). The relative costs of supercritical pulverised coal (PC SC), ultra supercritical (PC USC), AFBC, PFBC, IGCC and a combined cycle gas-fired plant were determined. The results are shown in Table 3.

The project costing model used indicates that specific capital cost ($/kW of installed electrical capacity) is the single most important factor in determining commercial competitiveness. Where a secure supply of moderately priced natural gas is available the relatively low capital cost of new combined cycle gas turbine plants makes it difficult for new coal-fired plant, based on any technology, to compete commercially. Gas-fired plant has dominated the market place in many European countries, not least in the UK where the 'dash for gas' has resulted in many new combined cycle gas plants being built in recent years. However, considerations of availability and security of supply dictate that coal will continue to dominate the electricity markets of many countries not least the developing countries with large indigenous coal reserves and increasing demands for power. Indeed, even in the UK the government has announced a moratorium on the building of new gas plants pending a review of energy policy.

Ultra supercritical PC emerges as the leading clean coal technology in terms of cost of electricity and return on investment. Table 3 shows no increase in specific capital cost between subcritical and supercritical and a relatively low premium for ultra supercritical PC. CFBC and PFBC appear to produce electricity at a cost between that of PC and IGCC. The higher efficiency of supercritical PFBC compensates for its higher capital cost in comparison with subcritical CFBC. Historically, CFBC has occupied two niche markets: for the burning of low value fuels such as washery wastes and the repowering of PC boilers where the environmental performance is an important factor and the space to fit FGD is not available. Indeed, the fuel flexibility of CFBC may prove to be an important advantage for developing countries with indigenous low grade fuels.

On the basis of the Karita PFBC plant in Japan it can be assumed that a PFBC plant with a supercritical steam cycle might be offered with no significantly greater process risk than conventional technologies. Further development of PFBC will depend on the use of more fragile combustion turbines which in turn depend on the development of reliable hot gas cleanup systems. However, the Värtan plant has demonstrated the potential of PFBC for unobtrusive operation, with impressively low emissions, in an urban situation. The Cottbus plant will also be built in an environmentally sensitive location where the high profile of PC might be unacceptable.

On the study to date, IGCC emerges poorly from the financial analysis because of its high capital cost. We are currently reviewing these assumptions with contractors to see if we have missed some cost savings in prospect that may modify that conclusion. This high cost relates to the full heat recovery, entrained flow, oxygen blown IGCC processes used for the major demonstration projects at Buggenum, Wabash River and Puertollano. Even after allowing for exceptional additional costs associated with 'first of a kind' demonstration plants, considerable further cost reductions are required before IGCC can be considered competitive for power generation. It may be that the air blown, KRW type gasifier at Pinõn Pine will lead to the development of a lower cost system suitable for use with lower grade coals. Other developments are under way in the use of quench gasifiers which avoid the heat recovery step and claim to reduce capital costs to below 1100 $/kW. If these projections are proven then, with its superior environmental performance, IGCC may well have a promising future. However, at present, most of the new coal-fired units will be built in developing countries where superior environmental performance and high efficiency may be of secondary importance in the face of acute power shortages. The deployment of clean coal technologies is unlikely to progress beyond a few demonstration plants until they are able to offer low cost electricity.

Trends in power generation

IEA Coal Research maintains a database containing details of coal-fired power plants and has recently undertaken a survey of coal-fired power plant construction during the 1990s (IEA Coal Research, 1997; Couch, 1997).

Table 4 provides a summary of coal-fired power plants constructed or due to be commissioned before the end of 2000 in the OECD countries. The first point to note is that in almost all the countries shown the number of plants built or planned is much lower than that projected even as recently as 1993/94. The main reasons for this are deregulation of the electricity industry and the availability of cheap natural gas. A decade ago there was widespread opposition to the consumption of natural gas for 'low grade' uses such as power production or for industrial applications. Many OECD countries prohibited the use of natural gas as a primary boiler fuel. Natural gas was viewed as a scarce and valuable resource, which should be used carefully and for higher grade applications only. However, since the late 1980s there has been a significant swing in attitude towards the use of natural gas. This, combined with the perceived operational and environmental benefits has resulted in a large increase in the use of natural gas for power production (Doig and Morrison, 1997).

Table 4 shows that of the 127 units listed 100 are pulverised coal plants. Of these 100 units, 43 are subcritical and 57 are supercritical (Figure 1). However, a closer investigation shows an interesting trend (Figure 2). Almost all the supercritical capacity is being built in Europe, Japan and Korea often using US technology. Countries such as the USA and Australia, with large reserves of relatively cheap indigenous coals, have not been attracted to the efficiency gains afforded by the supercritical plants as has been the case in Denmark for example.

Figure 2 shows that almost all the PC plants are equipped with electrostatic precipitators (ESPs) for controlling particulates and low NO_x burners or other primary combustion measures for controlling NO_x. While 33 of the plants also have SCR for controlling NO_x, all but three of these are in Europe, Japan and Korea. More than 80 of the plants have FGD, most commonly wet scrubbers.

Concluding statements

What does all this tell us? At present PCC is the preferred technology in the OECD region and will remain so for the foreseeable future. It can meet even the most stringent emission standards applied in some European countries. It can equal the efficiencies of the best new developments. It is a clean coal technology. Niche markets for CFBC and PFBC with certain types of low grade coals may encourage their take-up. However, the future for IGCC depends on bringing down the costs to a point where utilities will consider the technology as an alternative to PCC. This is even more true for the developing world. Until then PCC, especially supercritical, will continue to dominate the market.

Table 1 PFBC units

	Equipment	Net output	Net efficiency HHV	Emissions SO_2	NO_x	Particulates
Värtan	2 x P200 + 1 steam turbine CHP only	135 MWe/ 224 MWt	CHP	80	65	>10
Escatron	1 x P200	80 MWe	36.4	90%	286	76
Tidd	1 x P200	70 MWe	35	90%	192	18
Wakamatsu	1 x P200	71 MWe	37.5	166	190	30
Karita	1 x P800	360 MWe	42	80	190	30
Cottbus	1 x P200 + 2 gas-fired boilers	71MWe/40MWt 74 MWe/220 Mwt with gas boilers	CHP	123	123	21

Table 2 Summary of IGCC development units

	Gasifier	Efficiency, LHV	Capacity, MWe
Puertollano Spain	PRENFLO	43%	288
Buggenum The Netherlands	Shell	43%	250
Wabash River USA	Destec	38%	262
Tampa Electric USA	Texaco Full heat recovery	39%	260
Pinõn Pine USA	KRW	43.7%	99
Cool Water USA	Texaco Full heat recovery + Quench gasifier	31%/23%	93

Table 3 Comparative capital costs of clean coal technologies

	Full load efficiency	Capital cost. $/kW
PC	40%	1000
PC SC	42%	1000
PC USC	45%	1040
IGCC	45%	1300
PFBC	44%	1130
AFBC	39%	1100
CC GT	58%	470

Table 4 Coal-fired units commissioned or planned in the OECD during the 1990s

Australia	9	PCC	subcritical steam	
Canada	4	PCC	subcritical steam	
	1	CFBC	subcritical steam	
Denmark	4	PCC	supercritical steam	all CHP
Finland	1	PCC	supercritical steam	
France	1	CFBC	subcritical steam	Gardanne
Germany	11	PCC	supercritical steam	5 CHP
	1	PFBC	subcritical steam	
Italy	2	PCC	subcritical steam	
	1	PCC	supercritical steam	
Japan	2	PCC	subcritical steam	
	18	PCC	supercritical steam	7 more units to be commissioned soon after 2000
	2	PFBC	subcritical steam	Wakamatsu, Tomato-Azuma
	1	PFBC	supercritical steam	Karita
	1	BFBC	subcritical steam	Takehara
Netherlands	1	PCC	subcritical steam	
	1	PCC	supercritical steam	Buggenhum
Poland	5	PCC	subcritical steam	1 CHP
	2	CFBC	subcritical steam	
Portugal	2	PCC	subcritical steam	
Republic of Korea	2	PCC	subcritical steam	
	20	PCC	supercritical steam	
	1	CFBC	subcritical steam	
Spain	4	PCC	subcritical steam	
	1	CFBC	subcritical steam	

	1	PFBC	subcritical steam	Escatron
	1	IGCC	subcritical steam	Puertollano
USA	12	PCC	subcritical steam	
	1	PCC	supercritical steam	
	1	EF	subcritical steam	
	3	IGCC	subcritical steam	Wabash River, Polk Power, Pinõn Pine

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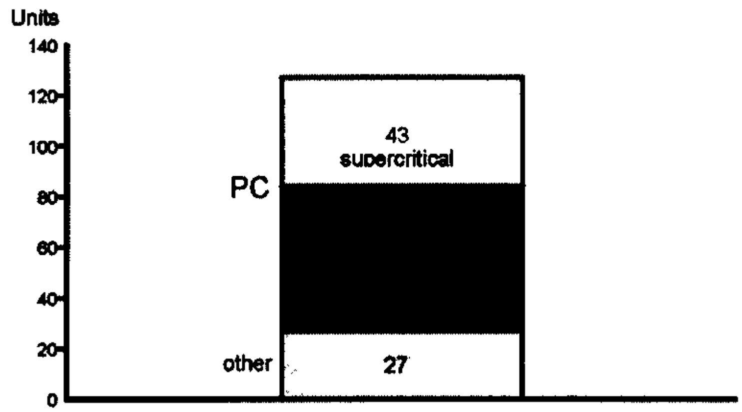

Figure 1 Coal-fired units built in the OECD during the 1990s

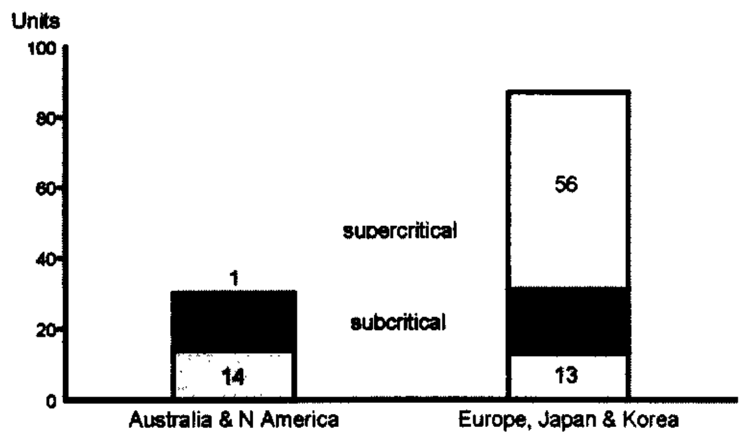

Figure 2 Types of coal-fired units by region

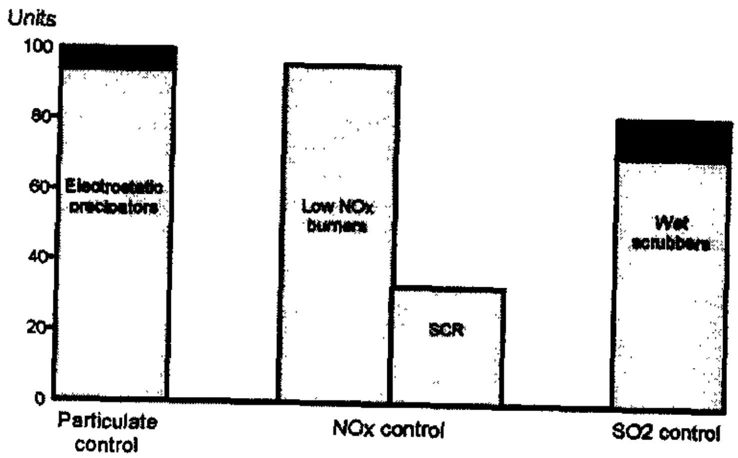

Figure 3 Emission control equipment on coal-fired plants built during the 1990s

DOMESTIC COMPETITIVE PRESSURES FOR CCTS

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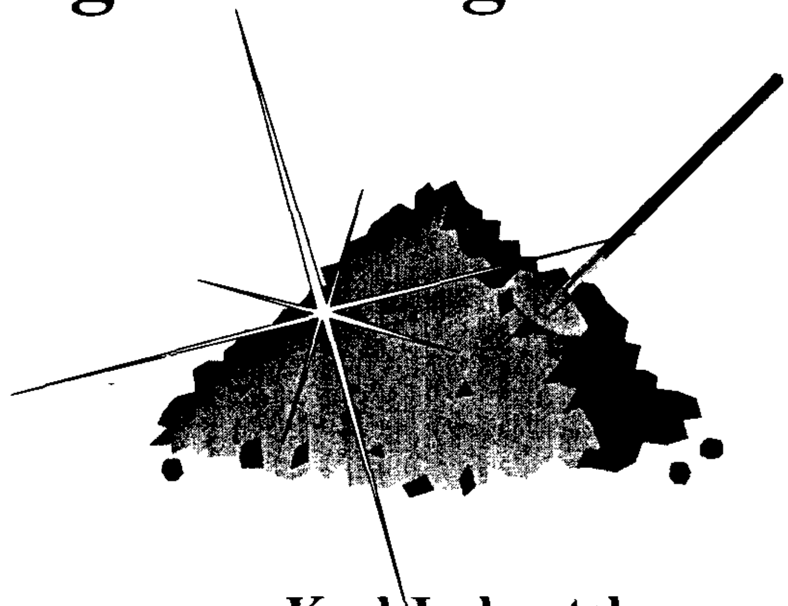
For copies of the paper contact the presenter.

Fuel For Thought

Financing Challenges for Clean Coal



Karl Jechoutek
Sector Manager, Energy Unit
The World Bank

Sixth Clean Coal Technology Conference, Reno, Nevada
April 28 - May 1, 1998

Question:

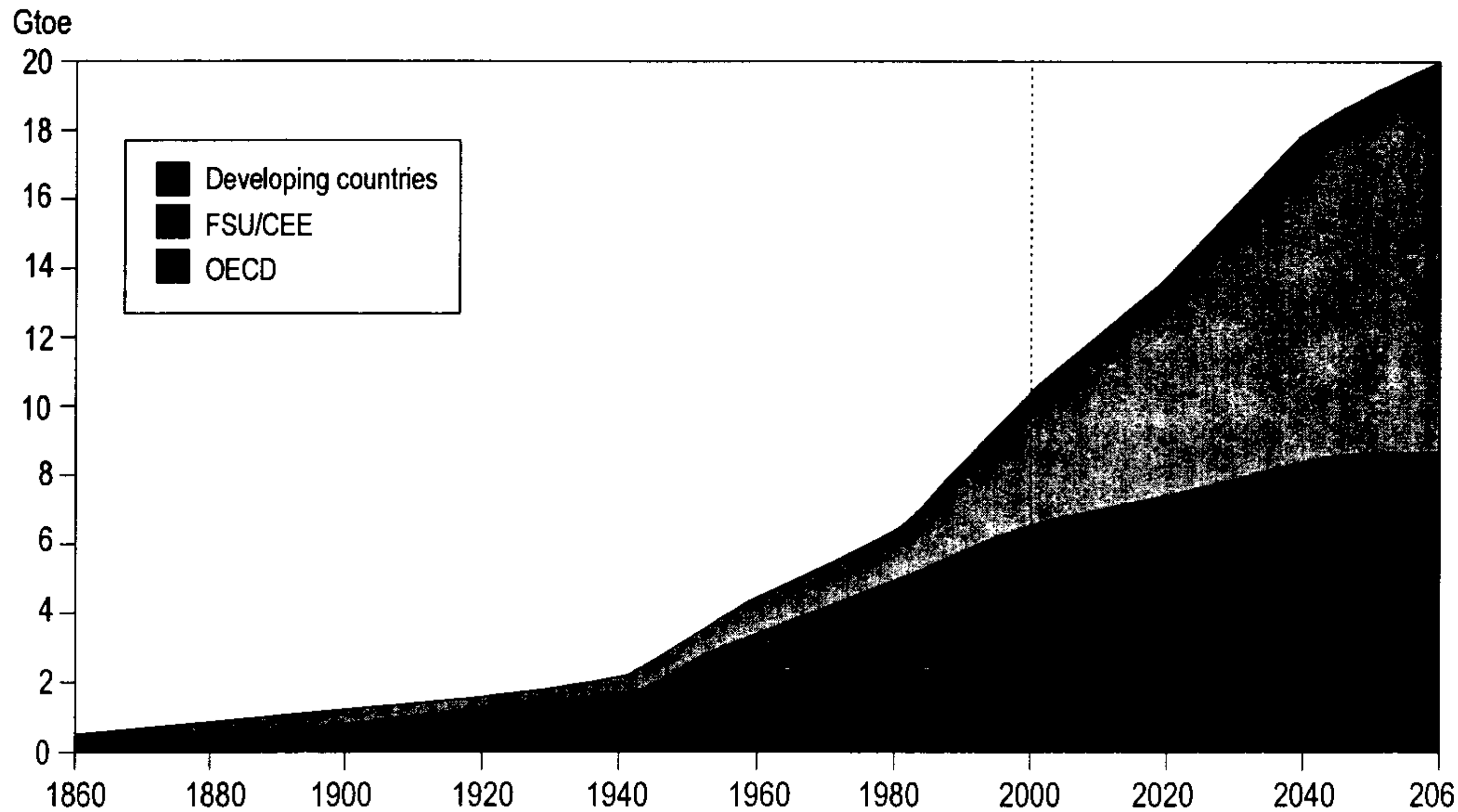
Can you win big if you only play the slot machines?

Answer:

Maybe, if you are very lucky. But it helps to look around the whole casino.

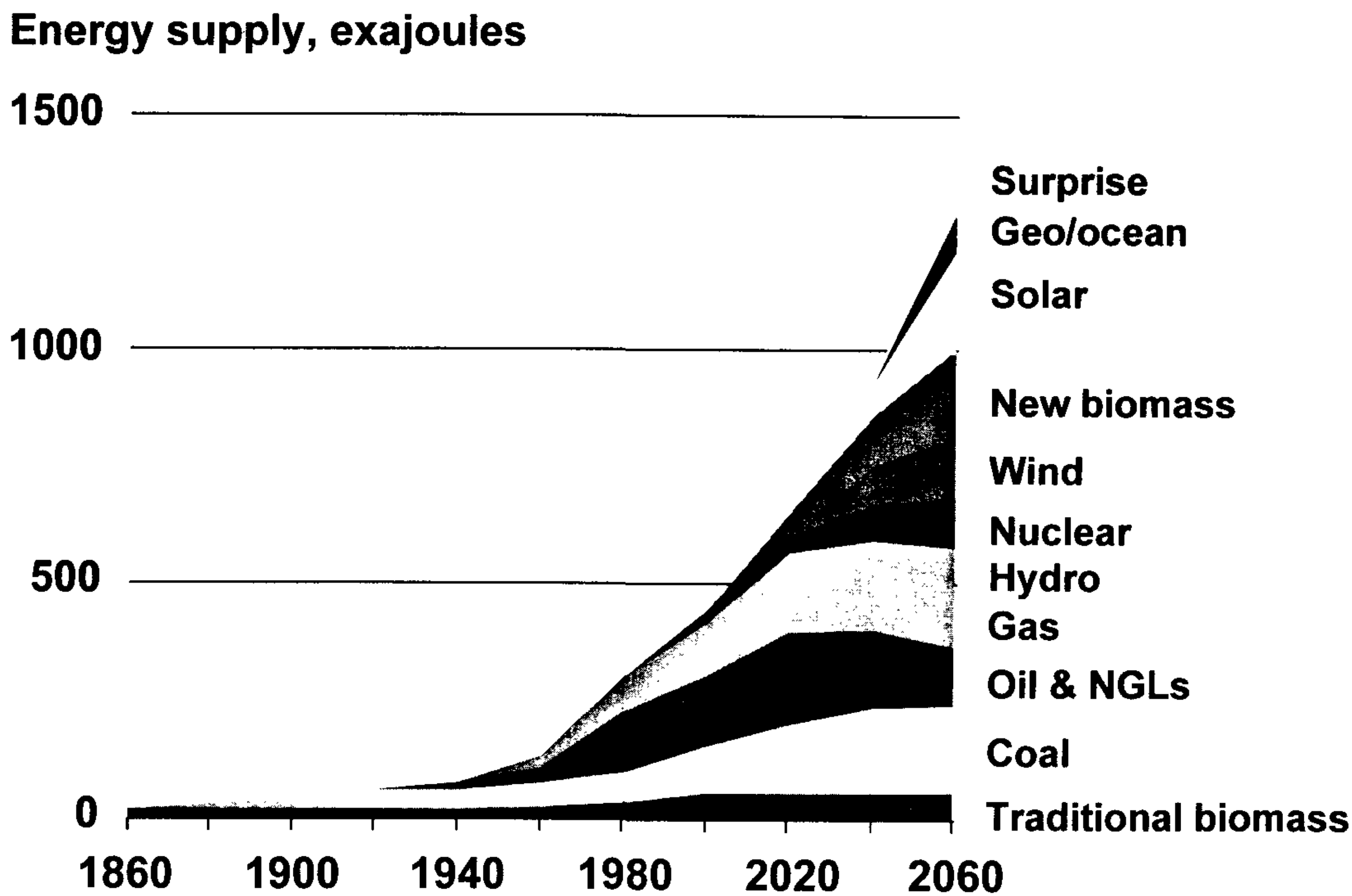
How much energy will the world need?

World Energy Demand: An Energy-efficient Scenario



Source: World Energy Council, World Bank.
The graph for the period 2000-2060 shows a scenario of future energy consumption based on current trends.

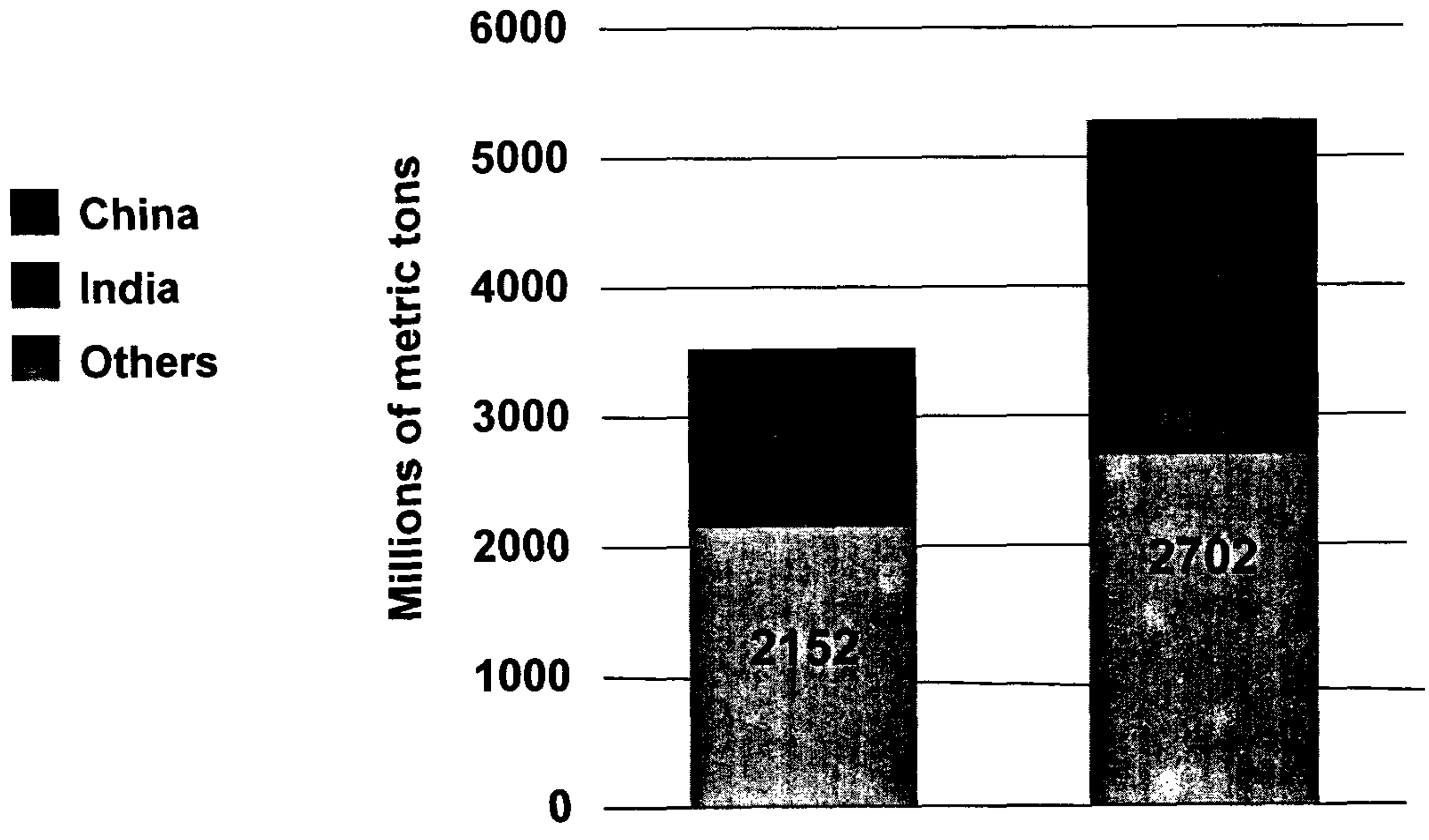
The Coming Energy Transition



Source: Royal Dutch Shell Group

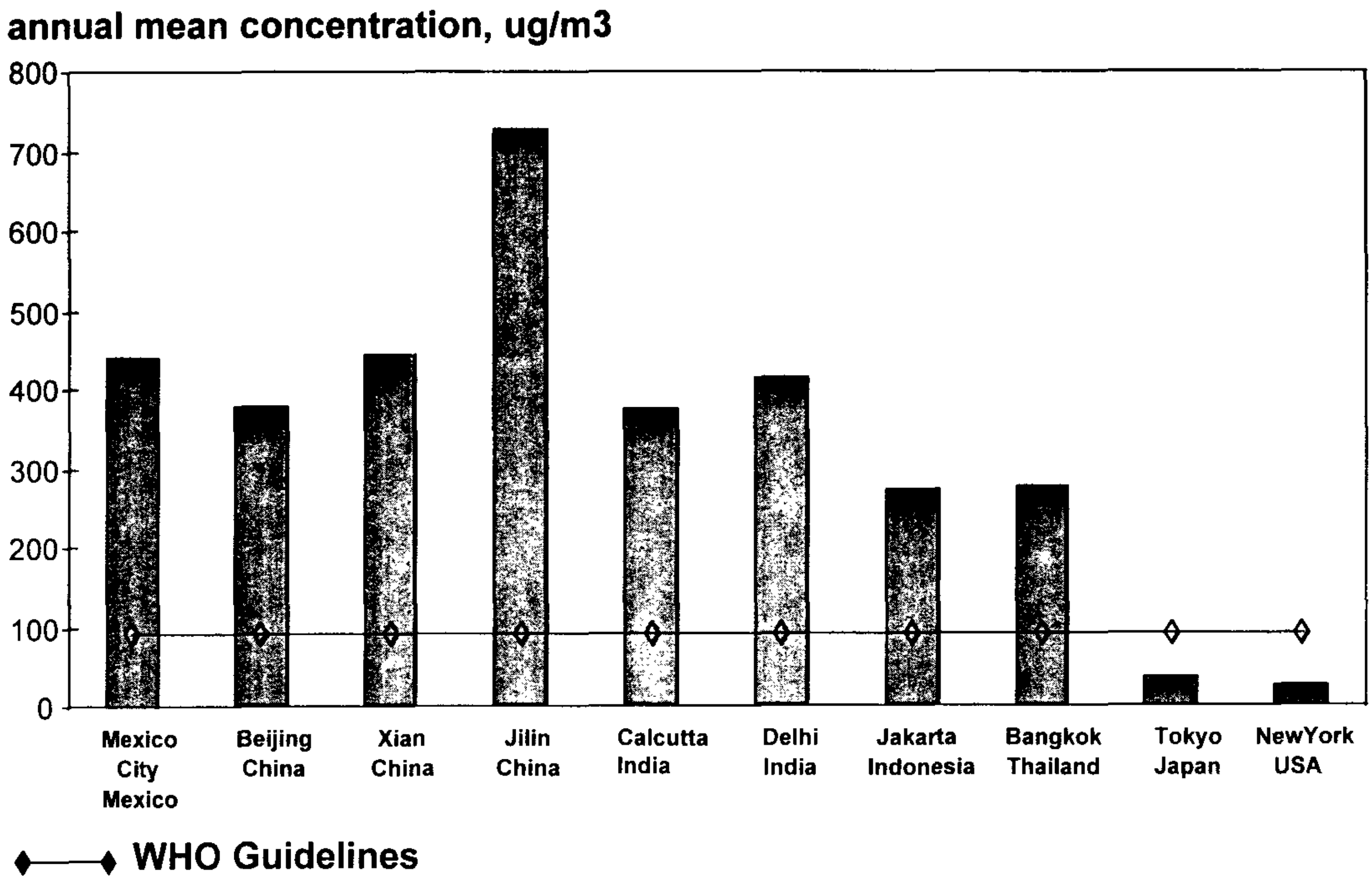
Coal Will Be Important

Coal Use Is Increasing



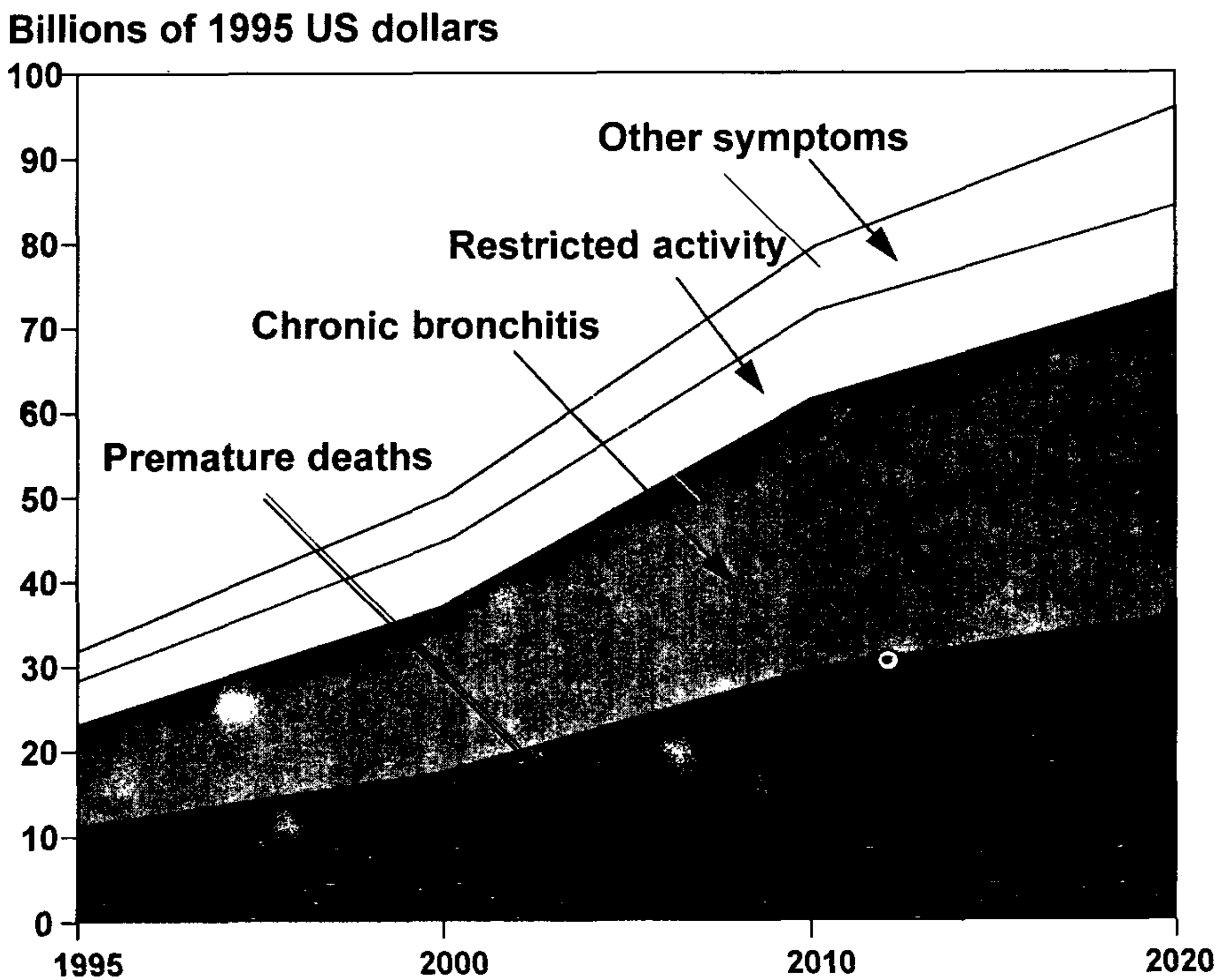
Source: IEA, World Energy Outlook, 1995

The Price: Pollution in Selected Cities (TSP)



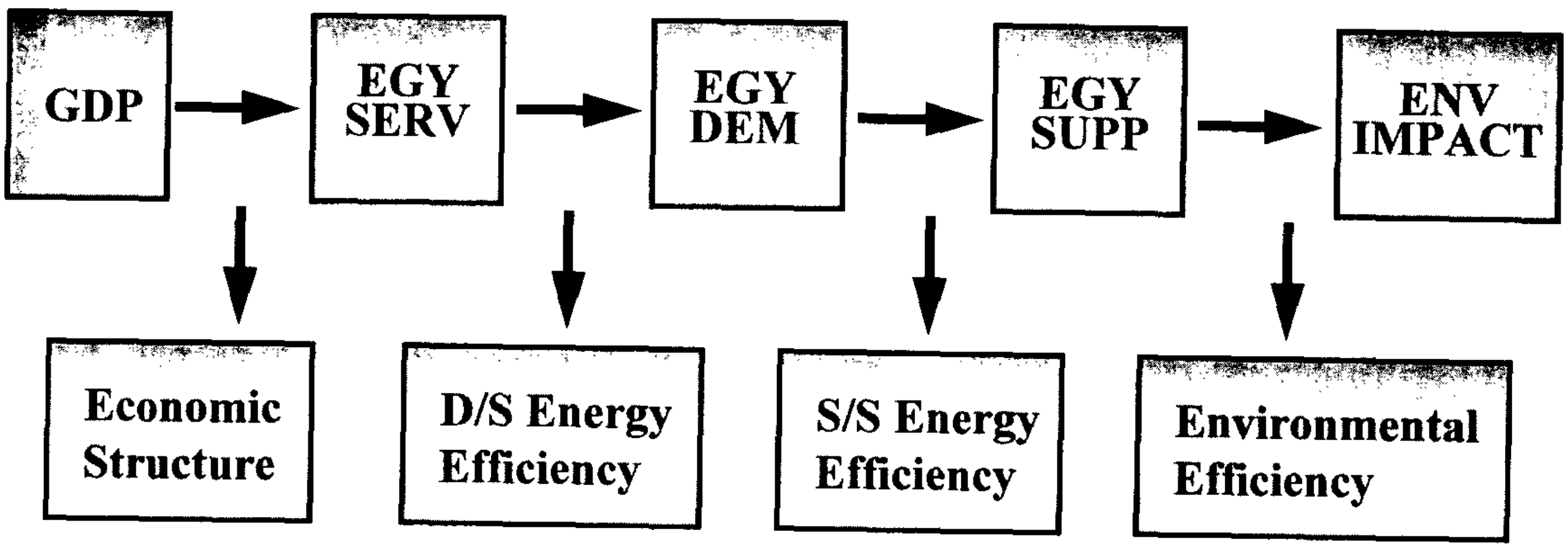
Source: OECD Environmental data 1995, WRI China tables 1995, Central Pollution Control Board, Delhi. "Ambient Air Quality Status and Statistics, 1993 and 1994", Urban Air Pollution in Megacities of the World, WHO/UNEP, 1992, EPA, AIRS database.

The Price: Health Costs in China



Source: Clear Water, Blue Skies; China's Environment in the New Century, World Bank, 1997.

The Challenge: Flexing Energy-Environment Links



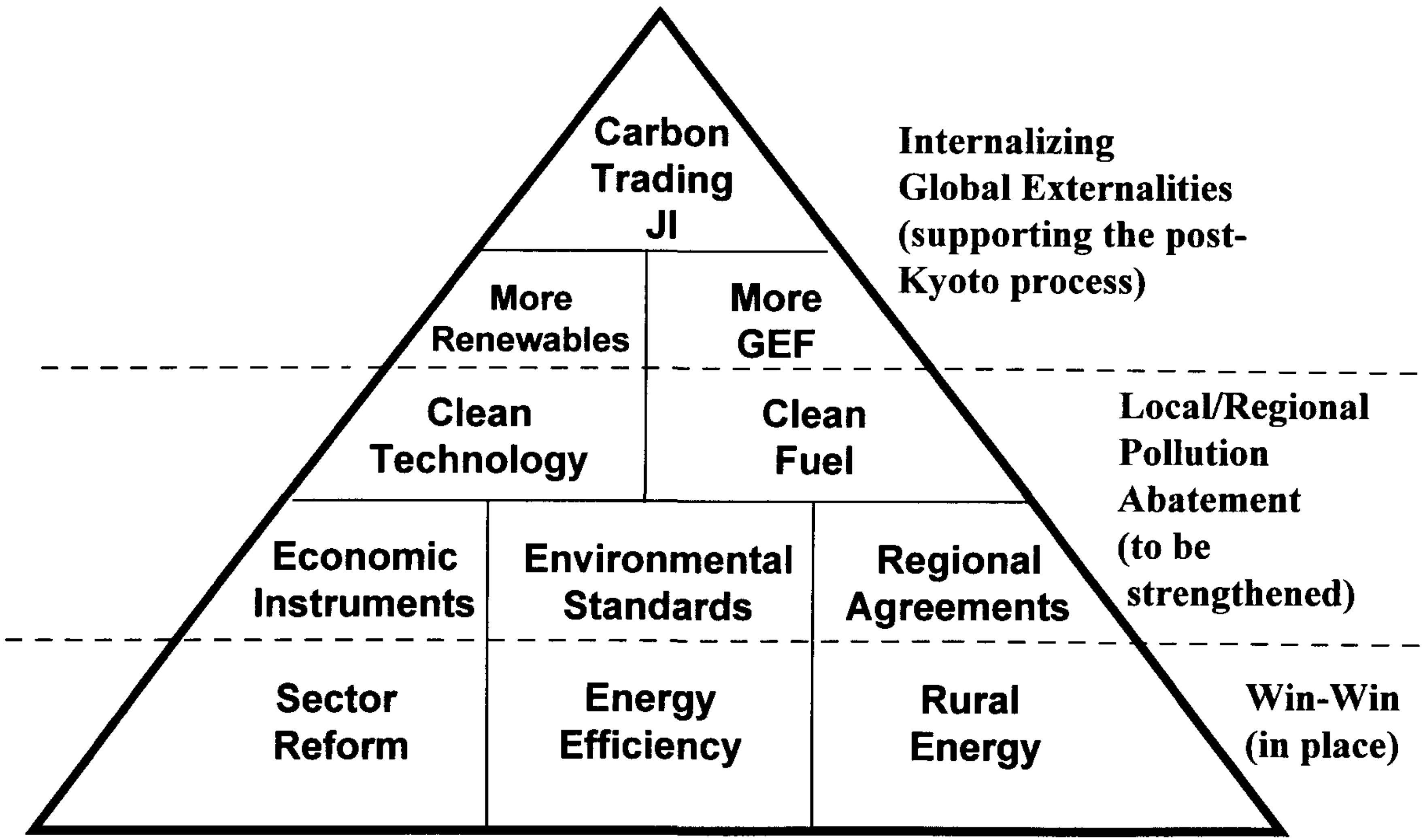
Environment Strategy for the Energy Sector -- Major Themes

I. Making Markets Work To Capture Win-Win Opportunities.

II. Internalizing Local and Regional Externalities.

III. Internalizing Global Externalities: Combating Climate Change.

Fuel For Thought: Strategy For The Year 2000

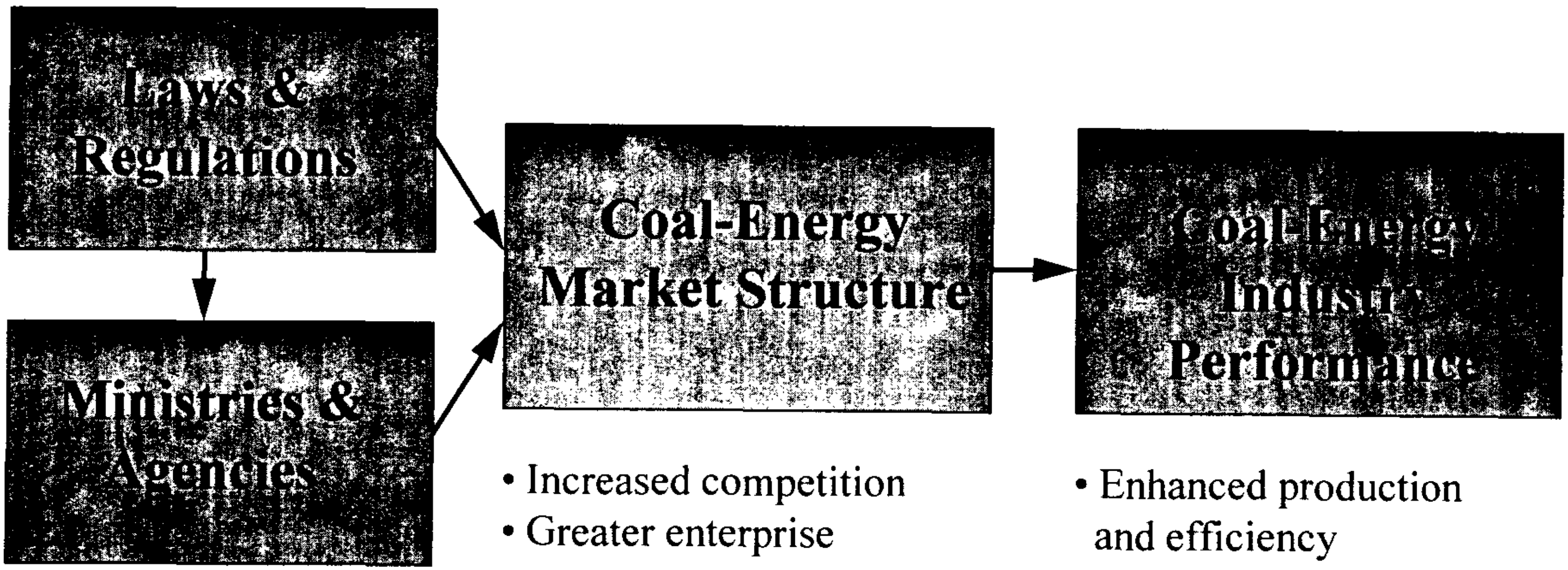


Making Markets Work

- Pricing
- Reform
- Energy efficiency
- Fuel switching
- Power and gas trade
- Hydro with full attention to social and environmental issues
- Renewables where economic

Making Markets Work: Coal

Reform & Restructure Policy Framework



- Increased competition
- Greater enterprise autonomy

- Enhanced production and efficiency
- Reduced cost
- Improved environmental performance
- Improved technology applications

Bringing Cleaner Coal into the Picture

- Reform/restructure the coal sector and coal user sectors.
- Market pricing of coal and other fuels.
- Open traditional monopolies to competition.
- Encourage private investors.
- Eliminate distortions that block efficiency in mining, transport, and power use.
- Seek incentives to scale up market for new technologies.
- Improve environmental standards.

The Evidence on Clean Coal So Far: Limited Success

- All eyes are on climate change - why tinker with coal when fossil fuels are the problem?
- Clean coal technologies are costly - where is the incentive?
- Coal Sector reform is slow and painful - no market signals in key countries.
- Pollution standards are sub-optimal.

Example: China

From "Clear Water, Blue Skies":

- Diversification into gas.
- Coal washing looks attractive to control dust.
- District heating and more efficient equipment.
- FGD and ESP for power plants.
- Higher prices, emission taxes, standards.

Example: India

Early impressions from a coal and power study:

- Clean coal technologies are not yet very competitive.
- Environmental mitigation can be achieved more cost-effectively through sector reform, T&D rehab, DSM.
- Coal preparation is a robust technology attractive for India, if sector reform takes place.

Kickstarting the Market I

Information Offensive:

- ◆Clean coal is a good instrument to address climate change (efficiency gains in China, India).
- ◆There already are competitive technologies (coal washing, supercritical).
- ◆Repowering is good business for private power investors.
- ◆GEF is there for you.

Kickstarting the Market II

More Aggressive Sector Reform:

- Deregulate coal pricing and allocation systems.
- Introduce competition in the coal and power sectors.
- Open the coal chain to private investors.

Kickstarting the Market III

Setting Standards:

- ◆ Apply the World Bank's Pollution Handbook.
- ◆ Get environmental standards to internationally acceptable levels, so technology is competitive.

New Tools After Kyoto

Joint Implementation

- ◆Carbon Offset Opportunities.
- ◆Cost-effective Project in Emerging Economies.

Global Carbon Initiative

- ◆Carbon Investment Fund.
- ◆Certification and Verification.

Conclusion

Try all the games, not just one.

- ◆Support sector reform vigorously.
- ◆Support sound emission standards.
- ◆Include a broad spectrum of technologies.
- ◆Use climate change mitigation as an opening for clean technology.
- ◆Invest in the clean coal chain.

LUNCHEON

Issue 4: New Markets for CCTs

NEW MARKETS FOR CCTs

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ABSTRACT

Markets for Clean Coal Technologies (CCTs) should be demanding new products at a rate faster than infrastructure growth can handle, but that is not necessarily what is happening. The driving forces are strong, so what is missing?

First, a look at the market place by size, fuels, world area, and a view of the trends. The shifts occurring in customer profiles can give us a clue to the hesitation in accepting the new technologies. Independent power practice versus traditional power company purchasing practice require different approaches. In addition, the slowdown of concluding IPP projects in the emerging markets has had a major effect.

Market drivers for CCTs are strong, especially in the environmental arena. Emissions, waste disposal, and water use are beginning to receive monetary credits, especially where co-products can be sold. Banks are leading the way in this area.

Many barriers still exist in both supply infrastructure and in customer acceptance. We will discuss these as well as the cost curve versus first-of-a-kind costs, but the shift of owners' risk to suppliers' risk is still a significant barrier.

Several formulas, based on specific successful projects, may be helpful in opening the door to a higher level of market penetration for CCTs.

INTRODUCTION

Upon examining the issue of introducing new technology to the power generation market, we see that power generator profiles are changing too fast to have a marketing formula last more than a few months. Barriers to new technology introduction can turn, overnight, into regulations that force the use of Clean Coal Technologies (CCTs). Technology developers need to be ready to offer the correctly packaged technology when those changes occur.

The following paper draws from real examples, successes and failures, as well as the author's personal experience with introducing combined cycle to the power industry in the late 1960s and early '70s. It examines various aspects of the CCT market including world area, fuels, trends, and market forecasts. These are issues that must be addressed to spur acceptance of CCTs in the world market.

POWER GENERATION MARKET

GE has plotted worldwide power generation orders, historical as well as a forecast of future orders, against the Gross Domestic Product (GDP). Figure 1 compares the forecast plotted in 1994 with the 1998 view to show the effect of the major aberration that started in 1993 called "deregulation."

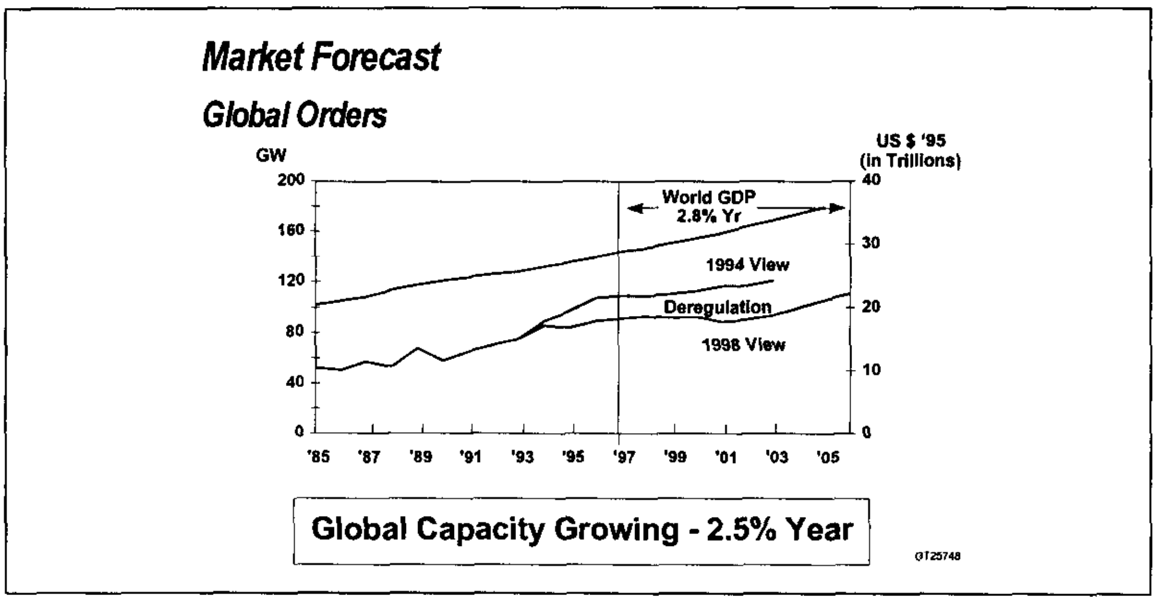

Figure 1.

The decline in the forecast rate of orders, caused by deregulation, is significant and is directly related to a three-year delay in one of GE's CCT projects. When deregulation occurs, and before the rules are clear, there tends to be a period of delay in decision making. If we address our technology packaging to the implications of deregulation, we may be able to create a positive effect. Its influence is spreading across the world, carrying the trend of delayed orders through the next few years, but there is still a large market in which to introduce CCTs.

Figure 2 is a historical/forecast plot, by world area, that shows a fairly level market with 50% of CCT installations in Asia, 30% in Europe, and 20% in the Americas. The forecast total of gigawatts (GW) over the next 10 years is 950, with GE forecasting that the largest market will continue to be Asia.

Also forecast is the Asian financial crisis' affect on the market, a 16 GW drop that is expected to be offset by surges in the European and American markets (Figure 3).

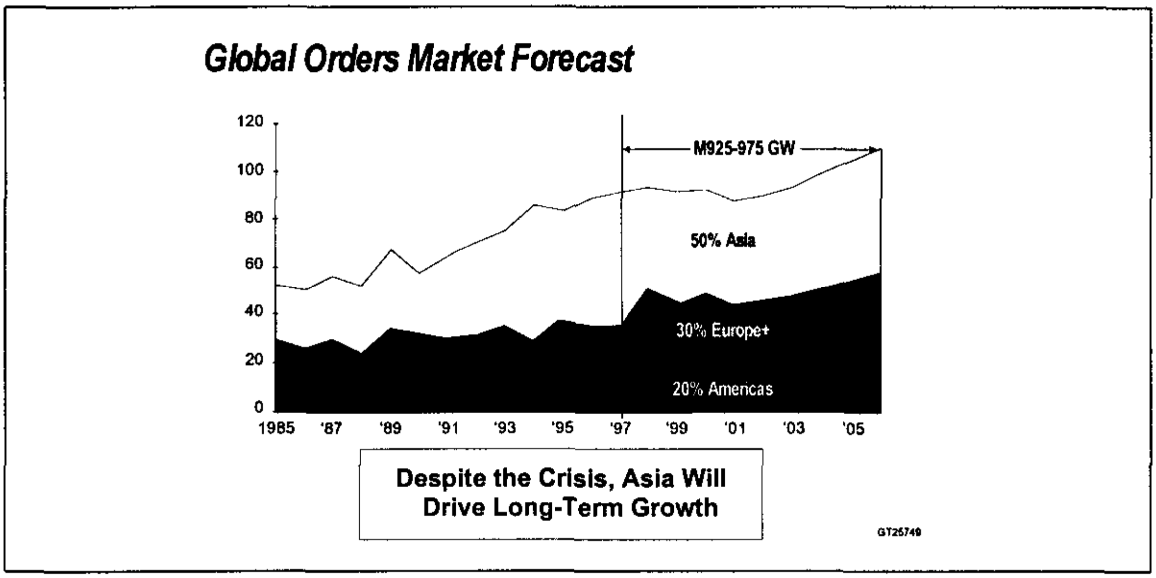

Figure 2.

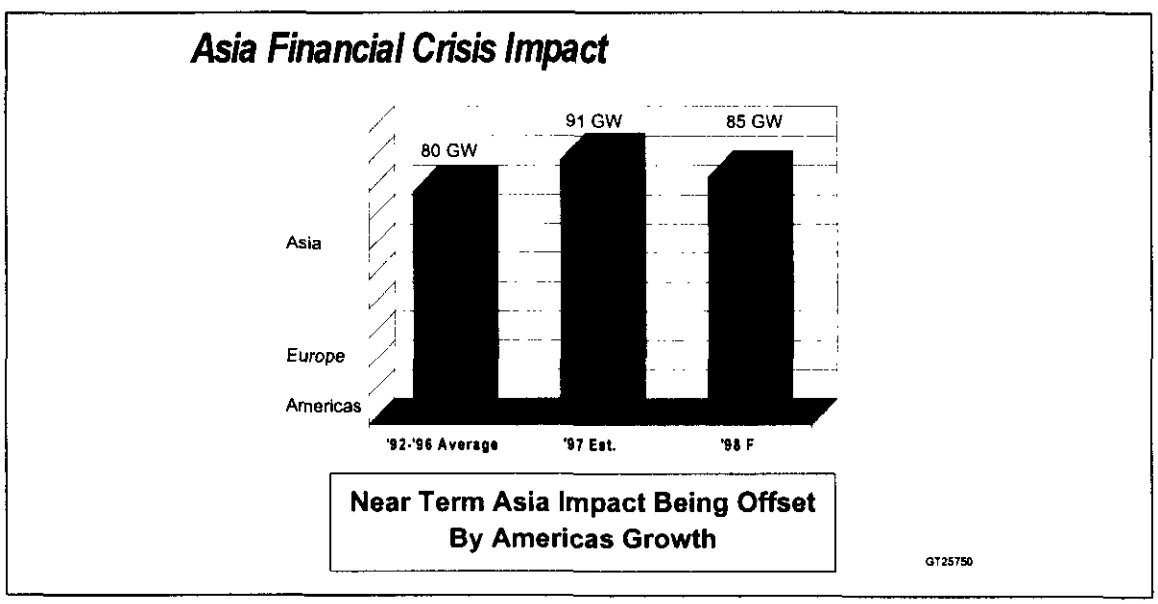

Figure 3.

GE's non-USA forecast for world power generation is 90% (Figure 4). China is forecast to be the leading power market, with a greater percentage of the market than cumulative sales in Japan, Korea and Taiwan. And CCTs are expected to come into demand in India soon. With such a high level of activity forecast in the Asian market, we must be aware that Asian countries have specific power generation needs, requiring modifications to the U.S. version of CCTs.

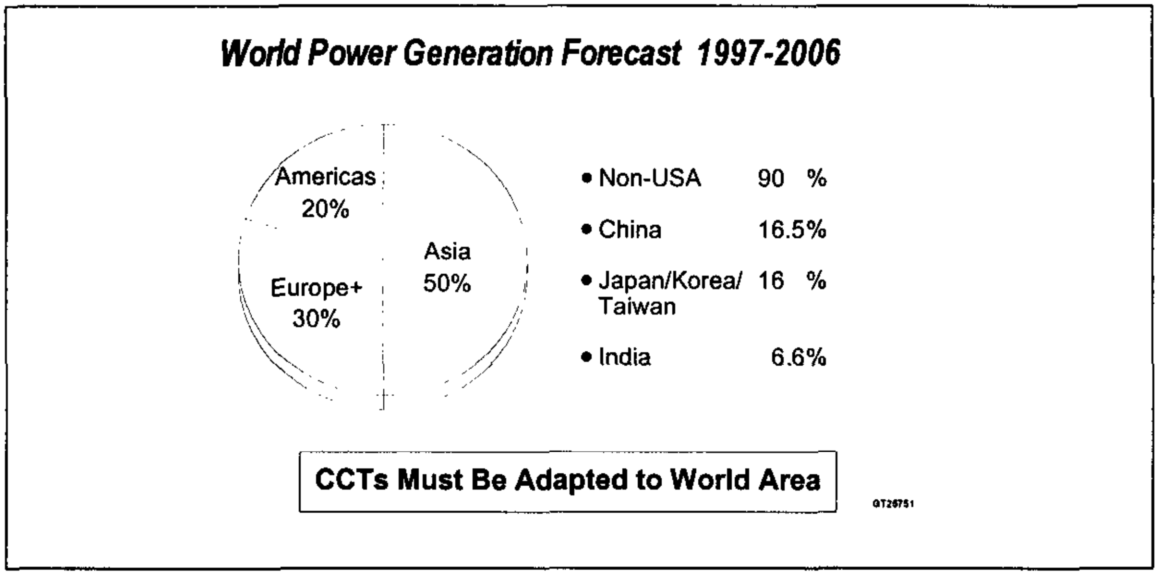

Figure 4.

Narrowing down the technology classifications helps to focus more closely on the portion of the market that can be served by CCTs (Figure 5). The gas turbines and combined cycles shown here do not normally use coal. However, the forecast does include some CCTs in the IGCC classification.

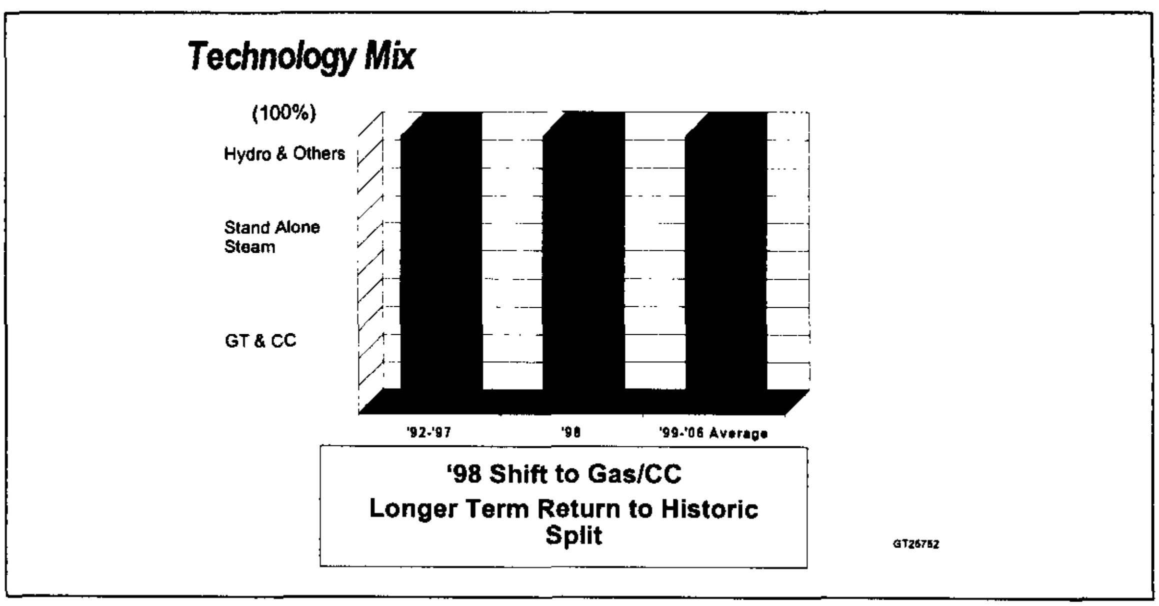

Figure 5.

combined cycles until Westinghouse came into the market and then within six months both companies received orders.

First-of-a-kind costs hold back new technologies when suppliers' finances cannot support installation of the first few plants. The United States Department Of Energy has helped immensely by providing funding for the first installations of CCTs. However, one installation only teaches enough to know what to do on the second and does not necessarily create marketability. Many technologies will probably still need financial assistance on the second and third projects.

IGCC ACTIVITIES

Despite all the barriers to CCTs, with this specific technology we have managed to develop about 5000 MWs of IGCC projects around the world (Figure 12). Unit sizes range from 40 MWs to 550 MWs including a variety of fuels, ten different gasifiers, and applications that cover repowering, cogeneration, and polygeneration where multiple products are co-produced. The 21 plants listed here represent a small penetration in the overall market, but are very encouraging. They have made it through the barriers. The success of each of these plants, particularly the nine that are operating, has led to a wide spread interest in IGCC.

IGCC Penetration

Customer	C.O. Date	MW	Application	Gasifier
SCE Cool Water - USA	1984	120	Power/Coal	Texaco - O_2
LGTI - USA	1987	160	Cogen/Coal	Destec - O_2
Demkolec - Netherlands	1994	250	Power/Coal	Shell - O_2
PSI/Destec - USA	1995	260	Repower/Coal	Destec - O_2
Tampa Electric - USA	1996	260	Power/Coal	Texaco - O_2
Texaco El Dorado - USA	1996	40	Cogen/Pet Coke	Texaco - O_2
SUV - Czech.	1996	350	Cogen/Coal	ZUV - O_2
Schwarze Pumpe - Germany	1996	40	Power/Methanol/Lignite	Noell - O_2
Shell Pernis - Netherlands	1997	120	Cogen/H_2/Oil	Shell/Lurgi - O_2
Puertollano - Spain	1998	320	Power/Coal/Pet Coke	Prenflow - O_2
Sierra Pacific - USA	1998	100	Power/Coal	KRW - Air
FIFE - Scotland	1998	120	Power/Sludge	BGL - O_2
API - Italy	1999	250	Power/H_2	Texaco - O_2
EXXON - Houston	1999	40	Power/H_2/CO/Pet Coke	Texaco - O_2
ISAB - Italy	1999	500	Power/H_2/Oil	Texaco - O_2
STAR - Delaware	1999	240	Repower/Pet Coke	Texaco - O_2
IBIL/Sanghi - India	1999	60	Power/Lignite	Tampella - Air
Sarlux/Enron - Italy	2000	550	Cogen/H_2/Oil	Texaco - O_2
FIFE Electric - Scotland	2000	400	Power/Coal/RDF	BGL - O_2
GSK - Japan	2001	550	Power/Oil	Texaco - O_2
Nihon Sekiyu - Japan	2003	350	Power/Oil	Texaco - O_2
		5080		

GT25747A

Figure 12.

Figure 13 shows a forecast for a significant number of coal, steel mill, and heavy oil applications. Some applications for CCTs have been categorized as planned and some are still being evaluated. All areas of the world are now involved in some form of CCT marketing but many areas will take 5-10 years to eliminate the barriers. Some of the projects are spin-offs from CCT and are contributing to building experience and reducing costs as well as helping to finance further CCT progress. Spin-offs are very important, even if they are not directly related to the main stream CCT market. Note that oil applications outweigh coal and steel put together. All we have to do is convert two thirds of these opportunities into orders over 10 years to meet the 4% goal for market penetration.

IGCC Worldwide Activity

		Americas		Europe		Asia Pacific	
		Projects	MW	Projects	MW	Projects	MW
Under Construction or Planned	Steel	2	480	4	680	2	360
	IGCC	19	3,030	23	6,710	41	15,400
In Evaluation	Steel	11	1,970	15	1,890	9	1,590
	IGCC	8	1,908	13	4,590	36	20,950

35 GW Oil and 18 GW Coal, and 7 GW Steel
Total 60 Gigawatts

GT25778

Figure 13.

CCT DRIVERS

GE concedes that environmental regulations are a major market driver (Figure 14). However, nobody buys a CCT unless it provides economic benefits. Economic benefits are derived from efficiency and low initial and operation and maintenance (O&M) costs. Efficiency provides environmental benefits but does not strongly affect the economic formula for low cost coal. In addition, most buyers think CCTs are too expensive. This can only be reconciled after a significant number of plants have been built. In order to ensure a second order and a third, we must concentrate on the cost of electricity as well as operating efficiency.

CCT Market Drivers

- Environmental Is Major Driver
  - Acid Rain
  - Global Warming
  - Heavy Metals

  As Tightening Occurs, Old Technologies Costs - Increase CCT Costs - No Increase

- In the Real World There Is Only One Driver - Economics
  - Efficiency Still Has Low Value for Coal
  - Reported High First Costs for CCT Need to Be Reconciled
  - O&M Makes Up the Rest of the Cost of Electricity

Must Concentrate On COE, Not Efficiency

GT25780

Figure 14.

Cost of electricity (COE) can be lowered by many means (Figure 15). One way is to find an application that has economic leverage. Repowering saves on first cost and may bring stranded assets into competition. Cogeneration saves one third of the fuel cost, while polygeneration (selling co-produced products) is a factor that carries the most leverage. It can also potentially solve the perplexing CCT problem of load shedding at night.

Cost of Electricity Can Be Lowered

- Find an Application That Has Economic Leverage
  - Repowering - Bring Stranded Assets into Competition
  - Cogeneration - Save 1/3 Fuel Cost
  - Poly Generation/Co-Production - Produce High Value Products to Lower Electricity Cost
- Sell By-Products
- Establish Local Sourcing
- Use Fuel Cost Differentiation

Selected Applications Can Pull Through CCTs

GT25779

Figure 15.

It is possible to vary the production of co-produced products by value pricing. Japan could make power in the daytime when it is most valuable, and co-products at night. Another suggestion is to sell byproducts, something everyone in the market is working on. It is also possible to establish long term local power sourcing and technology transfer to lower the COE. All of these methods really work, even if the implementation is not easy. Lastly, it is possible to use what we call "fuel cost differentiation" For example, both the Polk and Wabash stations use lower cost coals than would be used for conventional technologies.

The most important driver of CCTs in the market may be to find a fuel that is disadvantaged, an "opportunity fuel," where only a CCT can meet the environmental standards (Figure 16). All fuels have some variation in price. It is wise to concentrate on the cost of fuel from delivery to the burner tip, differentiating from the wide variety of pricing schemes used in the current market. Petroleum coke is currently so low in price that it is more economical than natural gas, even while covering the high costs of CCTs. Waste materials mixed in can cut the average fuel cost in half. GE has received several orders based on this practice.

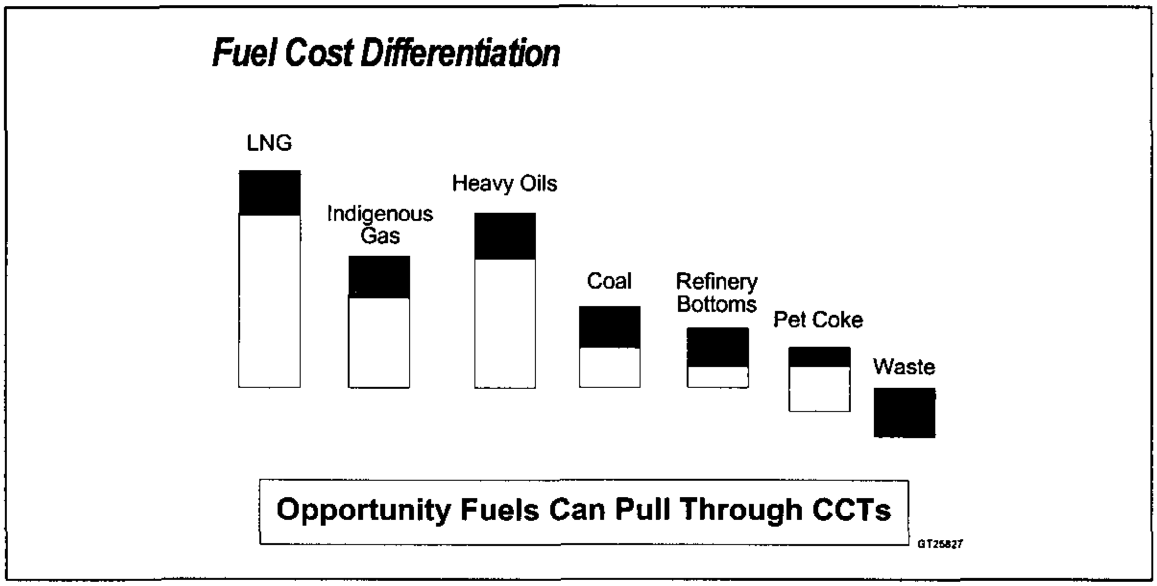

Figure 16.

Frequently, international buyers are confused by U.S. or European prices for first-of-a-kind plants. They don't have any way of relating those costs to their own situations. Figure 17 was created for the sole purpose of relating IGCC costs across the world. It was published by the GTC to help with this dilemma. The council is tracking worldwide bids and will attempt to keep the information up to date, based on published reports. While first costs vary widely, fuel costs may follow world levels, creating the need for a different CCT product in each country.

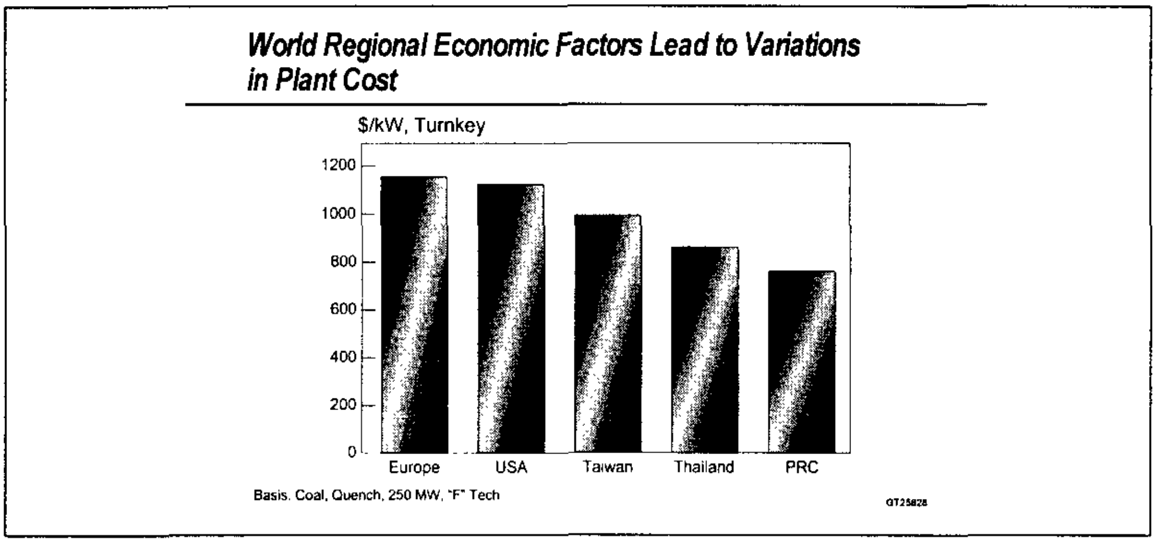

Figure 17.

Figure 18 illustrates the importance of focusing on COE. This simple chart creates a snapshot of energy costs for a wide variety of fuels and technologies. Combined cycles using natural gas are compared with IGCC and conventional steam units for power only plants. A general conclusion can be drawn that combined cycles with indigenous gas are usually more economical than IGCC unless a disadvantaged fuel such as petroleum coke is used. The Star Delaware IGCC is a case in point for IGCC petroleum coke.

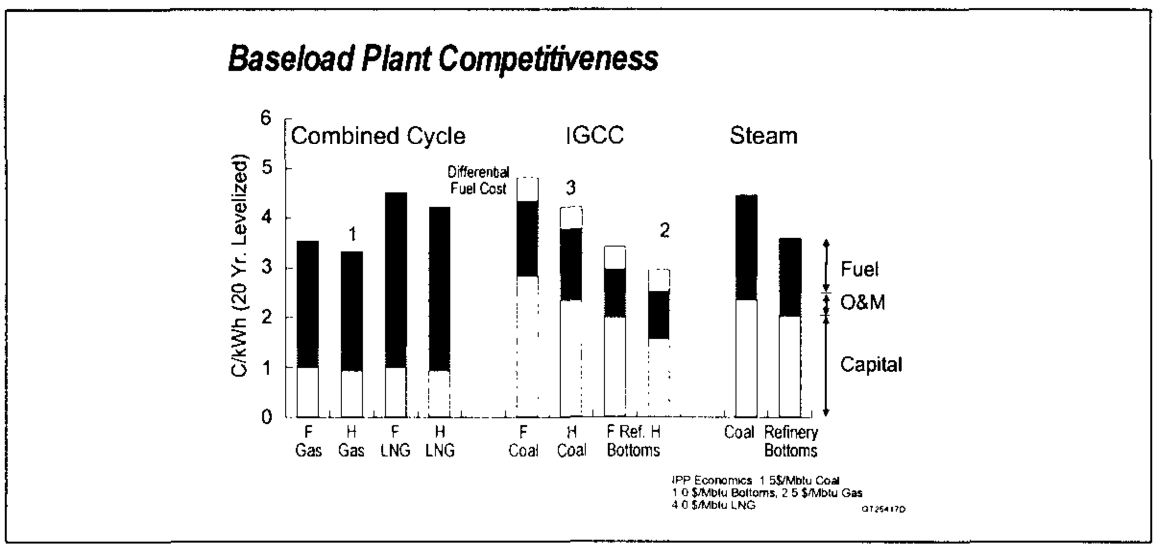

Figure 18.

Another general conclusion is that IGCC with coal, using today's F technology, needs fuel cost differentiation to compete even against liquid natural gas combined cycle. The Advanced Technology System (ATS) gas turbine technology sponsored by the United States Department Of Energy, shown here as H technology, appears to provide a COE breakthrough for IGCC for coal applications where indigenous gas is not available. In all cases, IGCC would provide lower COE for leveraged applications such as co-production.

SPECIFIC EXAMPLES

The Sarlux IGCC project is one of three in Italy using refinery bottoms (Figure 19). It has faced all the barriers we have discussed. Environmental and infrastructure required new laws, and the supplier and risk issues were addressed through a bankable turnkey bidding process. The bidding process was so new it required the owners to pay the losers for bidding. Today established formulas eliminate that issue. Financing on a project basis was accomplished for all three Italian projects based on strong guarantees from the suppliers and owners. First-of-a-kind configurations were derived from bank requirements concerning gasifier size, forcing a three-train configuration for 500 MWs. First-of-a-kind cost was addressed by competitive bidding. This is the lowest cost plant in Europe to date. It is an IPP project and is due on-line at the beginning of 2000. It can be done!

Sarlux - 550 MW IGCC Italy

Barriers	Solutions
Environmental	- New Law - Bottoms Not Allowed for Power Gen
Infrastructure	- New Law - Refineries Can Sell Power - IPP - Price of Electricity Established
Supplier Infrastructure/Risk	- Bankable Turnkey Consortium
Financing	- Project Financed
FOAK Cost	- Competition Established Reasonable Cost

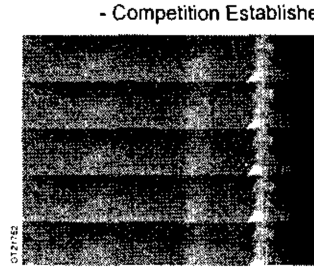

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Figure 19.

In the STAR IGCC project, fuel (pet coke) cost differentiation was used to create a competitive COE (Figure 20). This was combined with an improved purchasing formula: first, technology choice; second, definitive engineering; and third, competitive turnkey bidding. This new formula produced the lowest plant costs yet. It is an IPP project due on line in 1999. Innovative financing combined with experience gained in a previous false start has made this a fast track project.

Star - 240 MW IGCC - Delaware

Barriers	Solutions
Environmental	- Emissions / Waste Disposal Issues Forced CCT
Infrastructure	- USA IPP Rules in Place
Supplier Infrastructure/Risk	- Technology Choice Then Turnkey Bids
Financing	- Unique Off-Book Financing
FOAK Cost	- Fuel Cost Differential - Pet Coke vs. Indigenous Nat. Gas - Competitive Bidding - Technology - Competitive Bidding - Turnkey

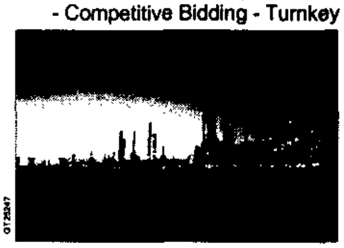

Figure 20.

The introduction of commercial IGCC technology to Japan has combined many of the subjects discussed today (Figure 21). It required the opening of the market to IPPs, which occurred in 1997. The General Sekiyu project benefited from the experience gained from Tampa and PSI 250 MW size gasifiers allowing the use of a two train configuration for the 500 MW plant. It is estimated to have reduced costs from the Sarlux configuration by $200 per kW. This CCT provided the lowest COE in the first round of bidding for IPPs in Japan. No enhancement by co-production, cogeneration, or repowering was needed in this power-only plant.

General Sekiyu - 550 MW IGCC - Japan

Barriers	Solutions
Environmental	- New Rules Eliminate Direct Firing - Tokyo
Infrastructure	- Japan Allowed IPP Bids 1997 - Clear Rules
Supplier Infrastructure/Risk	- Process Contractor/Power Contractor Tunkey Consortium
Financing	- Owner Financing
FOAK Cost	- Fuel Cost Differential Bottoms vs. LNG - IGCC Was Lowest COE Bid

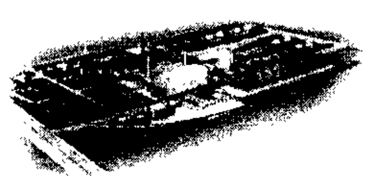

Figure 21.

IGCC activity in India includes 15 refineries studying the use of bottoms for power generation and some coal activity (Figure 22). One lignite IGCC has been ordered but was delayed for one year by environmental issues over the jetty. India, like Italy, is allowing refiners to sell power from wastes and to have foreign partners. The developer of one 350 MW project has announced, with government approval, its choice of IGCC, technology, and IPP partner. Another 500 MW project has received bids for CCTs and is beginning the bid evaluation. There are still no bidding process formulas so it may be some time before these plants are built. Many will have co-production and cogeneration as well as indigenous fuel so COE should be very competitive with LNG and Naphtha, currently used for some of India's power generation.

India IGCC Activity

15 Refineries and Some Coal Activity

Barriers	Solutions
Environmental	- Local Rules Driving Technology - First IGCC Coal Order Held Up 2 Years Over Objection to Jetty
Infrastructure	- New Plans Allow Refineries to Sell Power - No Rules in Place Yet for IGCC
Supplier Infrastructure	- First RFQ to Allow CCT Received 6 Bids - 3 CFB - 3 IGCC - Bankable Turnkey?
Financing	- Very Difficult Without Rules
FOAK Cost	- India Has 8,000 MWs of Refinery Bottoms - Usable by IGCC - Will Beat LNG/Naphtha - Credits for Sulfur Production, No Waste Important - India Has Low Quality Coal That Needs - PFBG - IGCC Technology - Coal Washing Technologies. Demo Planned

GT25843

Figure 22.

The People's Republic of China has more gasifiers operating than all other countries put together (Figure 23). Currently, none of these are used for power production. Considering the fact that China has the largest market potential, it will soon be ready for many of the CCTs developed worldwide. Successful experience developed by current projects will be very helpful in introducing CCTs to China but they will have to be packaged to meet China's special needs.

China

Most Gasifier Experience in World
400 MW Coal Demo Planned
Refineries Slow to React

Barriers	Solutions
Environmental	- Severe Pollution Setting Local Rules
Infrastructure	- China Very Knowledgeable on Gasification Breakthrough on IGCC & PFBC Expected This Year - Sites Chosen
Supplier Infrastructure	- China Will Have Its Own Formula of Local Participation
Financing	- Will Depend on Structure of Demo
FOAK Cost	- 4 Years of Effort Already Completed to Meet Economic Cost Levels

GT25844

Figure 23.

SUMMARY

There is no one formula for market development for CCTs. Figure 24 summarizes the discussion.

CCT Formula

Rule	- Concentrate on Each Technology Separately
Shot Gun	- Spread the Word - Help All Responses - Develop World-Wide Advocate Matrix - Grow Infrastructure Acceptance of Technology
Filter	- Find Individual Applications That Need the Technology - Use Feasibility Studies to Establish Worth - Verify Fuel Source - Consider Funding Sources
Rifle	- Develop Comprehensive Program to Close - Establish Ownership Formula/Contractual Relationships - Establish Advocate Contractor - Split the Responsibilities by Fault/Share - Establish Advocate Banks - Establish Knowledgeable Insurance Group
Operating Experience	- Make It Work - Correct Deficiencies - Redesign for Lessons Learned
Publish	- Good & Bad

Buy an Automatic Rifle

GT25845

Figure 24.

Concentrate on each technology separately. Each has its own virtues and unique competitiveness. If you are lucky enough to be involved in multiple technologies, let them compete against one another; they will each find a different market.

In the early stage, shotgun, spread the word, but be prepared to serve all requests just to learn what works. When you have spent several years at that, start filtering based on the lessons learned. Get out the rifle, find partners and start with the banks.

Make the first plant work, redesign for lessons learned. Publish both the good and bad. Then, if you have a better mouse-trap, you will need an automatic rifle.

PANEL SESSION 1

Issue 1: CCTs: Providing for Unprecedented Environmental Concerns

Current and Pending Regulations for Emissions from Coal Fired Sources

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The most significant concern with respect to environmental regulation shared by the utility industry's coal fired segment is uncertainty. Issues surrounding NOx, CO2, mercury, and fine particle emission reduction programs create significant uncertainty for the industry. The lack of interest the Clean Air Power Initiative (CAPI) in 1996 prematurely ended the best hope to date addressing this regulatory uncertainty. This presentation focuses on where current emission reduction efforts appear to be headed.

Nitrogen Oxides (NOx)

The regulatory development requirements of Title IV of the Clean Air Act relating to NOx were recently completed. On February 13, 1998, the DC Circuit Court of Appeals sustained the regulatory requirements established when the Agency promulgated NOx emission limits for Phase II of the Acid Rain Program beginning in January, 2000. The regulations applied NOx emission limits to nearly all coal fired utility boilers. These control requirements are expected to result in an annual reduction of approximately 2,000,000 tons of NOx.

The Title IV reductions will not be sufficient to achieve the purposes of Title I of the Clean Air Act-- attainment of the air quality standards for ozone. With respect to NOx, *attainment and maintenance of the ozone standard is the primary goal which will drive the need* for further NOx reductions from coal fired utility boilers beyond the year 2000. (Other concerns which will drive further NOx reductions include eutrophication and acidification of water bodies as well as visibility impairment and fine particle health impacts.) Already, the Ozone Transport Commission is establishing a NOx reduction and trading system for the twelve state Ozone Transport Region (OTR) in the Northeast. Similarly, the EPA's Ozone Transport SIP Call was driven by the need to suppress NOx emissions across the Eastern portion (22 states) of this country in order to make sufficient progress in attaining the air quality standards in this region. This proposed action calls for a 22 state reduction in NOx emissions equivalent to an average emission rate of 0.15 lb/mmbtu. Utilization was projected for the year 2007, and combined with the average rate to develop a cap on mass emission levels. This proposal calls for aggressive, but achievable, cost effective NOx reductions which would constitute the industry's contribution to attainment of the ozone standard. It is hoped that the program ultimately adopted by the states involved will be implemented using a trading program similar to the one being developed for the OTR. Such an approach will significantly reduce the cost of compliance and improve the viability of coal as a fuel.

Carbon Dioxide (CO_2)

In December, 1997, in Kyoto, Japan, the Administration committed to embark on a program to stabilize the emissions of Green House Gases (GHG) into the atmosphere at 7% below our Nation's 1990 level. The goal is set and clear. Many steps are still needed, though, before implementation of a program. If Congress ratifies the treaty, the Administration is committed to establishing a market based trading program patterned after the Acid Rain program. Necessarily, it will deviate from the Acid Rain program in its details, possibly to accomodate sequestration and other GH Gases besides CO_2; but nevertheless will attempt to use a market system to minimize the costs of this program.

Fine Particle (PM Fine)

Requirements, for fine particle control, are well in the future. It will be several years before the Agency has the ambient monitoring necessary to determine the extent to which SO_2 emissions contribute to the PM fine nonattainment areas. Furthermore, in just two years additional sulfur dioxide reductions will begin under Phase II of the Acid Rain Program. Additional mitigation of sulfates will require additional rulemaking. Here, although the goal is clear...attainment of the PM fine standard... the extent of additional control is yet to be determined.

Summary

The most significant near term environmental pressure on coal fired utility boilers will come from the need to attain the ozone standard in the Eastern U.S.. Nitrogen oxide reductions to an average level of 0.15 lb/mmbtu are thought to be necessary to attain this goal throughout the 22 state "SIP Call" region. In the longer run, GHG stabilization will constitute the most significant challenge. Clean coal options developed through the Department of Energy's Clean Coal Technology program will need to be aggressively implemented along with other carbon reduction approaches.

POLICY PERSPECTIVES REGARDING CLIMATE CHANGE

Gail McDonald
President
Global Climate Coalition
Washington, DC, USA

Thank you for asking me to participate in the panel today. First let me tell you about the Global Climate Coalition. GCC represents more than 200,000 individual companies engaged in manufacturing, forest management, agriculture, transportation, energy, utilities and mining. Our organization was established in 1989 to provide a forum for business participation in the scientific and policy debate on the climate change issue and we have been active since - on both the domestic and the international scene.

Our members agree that potential human-induced climate change is a legitimate and serious (social) concern that needs to be addressed further. The issue is not action versus inaction, but responsible action. And our members do not believe that the Kyoto Protocol is responsible action. We believe this for several reasons.

The issue of climate changes is still inadequately understood and, despite the politically correct belief that the "science is certain", our members believe that uncertainties do remain and that policies such as Kyoto, with its possible very negative economic consequences are simply not justified at this point.

The treaty would cost our economy in many ways. It is our firm belief that the only way that Kyoto's extremely short-term, by 2008-2012, and stringent targets below 1990 levels can be met is through a sharp increase in energy prices, with a simultaneous downturn in our economic potential, the loss of competitiveness and jobs.

Technology can help, certainly, but we are looking at a required significant decline in energy use by 2010 from business as usual, and our ability to adopt new technologies cannot fill this requirement in just 10 short years. Consider the history of Clean Coal Technology Initiatives. How far have these projects come in 11 years? Flexible market mechanisms such as emissions trading may help. But the jury will be out, until we know how much of our obligation can be met and until we know the rules of the road. How will trading work? This is yet to be determined and remember, these rules will not be determined by the market - they will be determined through international negotiations among 168 countries, many of whom do not understand markets. Of the168 parties tot the Protocol, 130 countries will not be impacted.

Finally, if there is indeed a climate problem, Kyoto is an ineffectual solution since it is not a global solution. All forecasts point to the fact that emissions from developing countries will outpace our own early in the next century. Kyoto does nothing to slow the emissions growth, even in the more developed of the developing countries - Mexico, China, S. Korea and, indeed could increase the expected rate of growth in these countries as industries move from the developed or industrialized nations to the developing world. Kyoto could be just a transfer of emissions from the United States, Japan, and Europe to other countries having no obligations. So, Kyoto could be economic pain, with absolutely no environmental benefit.

The Kyoto Protocol fails the sensible tests of the Byrd-Hagel resolution that was passed by the senate last summer by a 95-0 vote. It does not have the potential to cause a good deal of harm to the U.S. Economy. So, what should we do? The Global Climate Coalition is not a "Just Say No" group. We believe that there is a better approach. That approach does not involve legally binding emission reduction targets but instead involves:

1 - These include a cooperative effort by government and industry to assess the current voluntary emissions reductions programs, determine what works and what does not, and then aggressively pursue the successful programs.

2 - The Climate Action Plan, initiated in 1993 is saving almost 100 million tons of carbon per year, but more can be done. We can rely more on these voluntary programs.

3 - A more reasonable approach would involve a policy and investment environment, that would be conducive to increased private investment in new technologies and processes.

4 - We should identify and then modify impediments to a more rapid turnover of energy - inefficient capital stock.

5 - We should review the tax rules to explore the possibility of fostering greater investment in new energy efficient R&D, and then in the deployment of new technologies.

6 - We must develop and promote an investment climate to encourage the export of U.S. energy efficient technologies to developing nations.

The members of the Global Climate Coalition know that even Senate rejection of the Kyoto Protocol will not end the climate debate. Research will, and should, continue to evolve readily and there should be considerable progress in reducing scientific uncertainties while we are making advances in demonstrating technologies to deal with emissions reductions, on a long term basis. The members of GCC will be in the forefront of advancing this research, while continuning to participate in the voluntary programs that have, as pointed out, resulted in a reduction in the rate of growth in emissions by one-third. We will also participate at United Nations in the efforts to develop efficient and effective rules for emissions trading and joint implementation.

I have a paper for distribution (see attached) on the voluntary efforts undertaken by GCC members. The electric utilities have led these efforts. For their substantial investments and extensive efforts, they were promised DOE early credit. The Administration has yet to fulfill that promise. Given the low level of political support for the Kyoto Protocol, this is hardly the time to undertake more ambitious commitments. We have just begun to make tangible progress on reducing CO2 emissions as called for in the Treaty of Rio. A reasonable policy is to continue that strategy.

Voluntary Actions of GCC Members

By Gail McDonald
President

The **Global Climate Coalition (GCC)** is an organization of private companies and business trade associations representing more than 230,000 firms. Established in 1989 to coordinate business participation in the scientific and policy debate on the global climate change issue, the GCC places a high priority on scientific and economic research to advance the understanding of earth systems. Membership includes a broad range of businesses from virtually every sector of the US economy.

Large manufacturers in the iron & steel and paper industries join small businesses with common interests in maintaining the abundant and inexpensive energy that keep American standards of living the envy of the world. Transportation industries such as the airlines, railroads and automobile manufacturers share a common interest in US energy policies along with independent and investor-owned power generating companies, the coal & petroleum industries, chemical firms and owner-managed small businesses across the country.

The GCC believes voluntary action is the best policy approach given what we know - and don't know- about potential human impacts on climate. We also believe that implementing the increased regulatory controls called for by the Kyoto Protocol would be costly and would not produce the desired environmental benefit.

Past experience shows that voluntary programs provide important benefits to industry participants including access to leading-edge information, greater return on economic investments, and such intangible benefits as increased public awareness and recognition.
Government, society and the environment also benefit from voluntary programs. For example, a report prepared by the OECD Environment Directorate on industry voluntary programs noted that:

- Voluntary programs are flexible policy instruments to achieve environmental objectives in a manner which best suits the economic circumstances of the individual company;
- Voluntary agreements encourage co-operation between industry and government; and
- Voluntary agreements are able to achieve energy and environmental objectives faster than regulations.

The GCC has been a long-term advocate of the use of voluntary programs, including government-to-industry partnerships, to limit greenhouse emissions. Since 1993 GCC members have both initiated and participated in voluntary programs, and we were one of the first groups to support the voluntary approach outlined by President Clinton in his Climate Change Action Program. Regrettably, this type of approach has apparently been abandoned by the Clinton Administration as ineffective, when in fact it has led to a one-third reduction in emissions that would have otherwise occurred over the past six years.

I would like to take a moment to review ***some*** of the actions being taken by GCC members by focussing on two categories of actions: improving energy efficiency and developing new products and processes.

Category 1 -- Improving Energy Efficiency

1. The petroleum industry has undertaken the following actions:

   One company has cut emissions by more than one million tons of carbon over the past three years. It also began a program to eliminate leaks of methane from natural gas production and distribution systems, and won the 1998 EPA "Energy Star Buildings Partner of the year" award for its long-term participation in the Green Lights and Energy Star Building programs. Another oil company has built its solar investment into the second largest U.S. solar company. Another oil company has installed vapor recovery systems on storage vessels. And a number of other companies are improving efficiency by using co-generation plants at a number of their facilities.

2. Participation by the electric utility industry in the DOE Climate Challenge program, which is a partnership between the DOE and electric utilities to facilitate voluntary cost effective actions to reduce, avoid or sequester emissions of GHG's will reduce US greenhouse gas emissions by 47 million metric tons in the year 2000.

3. Participation in the Green Lights program -- an EPA program involving partnerships between the EPA, corporations, utilities, non-profit organizations and other groups in which those groups agree to analyze and upgrade lighting equipment with more energy efficient systems -- has lead to an annual savings of 2.5 million metric tons of $CO2$.

4. In 1994, the Chemical Manufacturers Association adopted a Climate Action Program to promote voluntary and cost effective efforts to reduce emissions. The CMA program includes companies representing about 90% of the chemical industry, and emphasizes evaluation and analysis of greenhouse gas emissions
   and adoption of appropriate and economic sound measures to reduce these emissions.

5. In October 1997 the iron and steel industry proposed a conceptual framework that, with the proper incentives, could lead to a 10% reduction in GHG emissions by 2010. The steel industry has already achieved a 45% reduction in energy consumption since 1975 and has reduced emissions through more effective utilization of materials, such as the recycling of iron bearing dust and sludges which reduce the amount of virgin iron ore necessary to produce steel and the processing of scrap steel that would otherwise not be suitable for recycling.

6. The Portland Cement Industry has increased energy utilization through continuous casting, as opposed to processing in series of batch steps. While domestic cement production has remained constant for the past twenty years, the energy used has decreased 27%.

Category 2: Developing New Products and Processes

GCC members are also at the forefront of the development of new products and processes.

1. For example, the automobile and oil industry recently announced the development of a series of advanced energy saving technologies made possible in part through the Partnership for a New Generation of Vehicles (PNGV) program between the automobile industry and the government. It is hopeful that these prototype vehicles will have fuel efficiency of more than 60 miles per gallon, feature electric hybrid powered engines, and weigh up to 40 % less than today's cars. A joint development program between members of the automobile and petroleum industries designed to produce a new generation of cleaner burning fuels was also recently announced. Several auto and oil companies also recently announced investments in a fuel cell company that began delivering city buses to Chicago to demonstrate the features of this new technology.

2. The Iron and Steel Industry along with the automotive industry developed the ultra-light steel autobody (ULSAB), which the industry believes will lead to reduced fuel consumption without compromising safety, comfort, and affordability of automobiles. They have also developed specialty steels used in electrical equipment such as transformers, capacitors, and motors that will help reduce energy lost in these units.

3. In the coal industry, projects have begun as part of the coalbed methane outreach program. This is a DOE/EPA program to provide technical and financial assistance for coal mine owners to promote energy recovery. Ten coal mine sites have been selected for demonstration of the recovery and utilization of methane. Several coal companies are involved in DOE's Motor Challenge Program as well.

4. The Electric Utility Industry has been the most active within industry in pursuing voluntary actions. Three examples illustrating the range of their initiatives are:

   a.. The EnviroTech Investment Fund is a combination of two venture capital funds with a total capitalization of 52 million dollars - EnviroTech and Utech - invest in companies that focus on emerging electric and renewable energy technologies that are more energy efficient than those in the current market place.

   b. The International Utility Efficiency Partnerships promote projects between electric utilities, international organizations and US government agencies that identify and support energy development in an environmentally beneficial manner. IUEP organizes technical support from US electric companies to assist foreign utilities and governments improving the efficiency of new or existing power systems. Ten projects are already under development in countries such as Argentina, Belize, Honduras, China and the Czech Republic.

   c. The Utility Forest Carbon Management Program expands utility industry efforts to manage carbon dioxide through domestic and international forestry projects. Trees are referred to as "carbon sinks" because they take carbon dioxide out of the air and store it in living plant tissue -- branches, stems and roots. Forestry projects can avoid greenhouse gas emissions by reducing deforestation and creating new carbon sinks through planting on pasture or agricultural land. In addition, forestry programs often have secondary environmental and social benefits -- restoration of degraded lands and protection of biodiversity.

For policy makers, voluntary programs represent a unique and innovative approach to addressing greenhouse gas emissions.

- They are easily adaptable to changing economic conditions.
- They can be tailored to unique national circumstances.
- They avoid costly and time consuming rule making and litigation.
- They harness the expertise, ingenuity and financial and human capital of the private sector.

Voluntary programs are a particularly appropriate mechanism to address the unique energy use patterns and opportunities for technological innovation found in U.S. industry.

- This is because voluntary initiatives enable industry to flexibly pursue energy efficiency improvements in combination with environmental protection and productivity improvements when capital investment and modernization decisions are made.

All of these climate initiatives are, by any standard, new, and they should be given adequate time to work. They should be formally assessed, and the best programs should be replicated as often as feasible.

A U.S. UTILITY PERSPECTIVE: MEETING THE CHALLENGE

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MEETING ENVIRONMENTAL CHALLENGES
THE GERMAN EXPERIENCE

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ABSTRACT

In the past, the German Government passed a package of laws which limits the amount of emissions into the air and which forced the power plants to retrofit comprehensive environmental protection plants. Stringent emission limits have been set for dust, carbon monoxide, sulphur dioxides, chlorine, fluorine, and nitrogen oxides. Therefore all power plants have an electrostatic precipitator in order to comply with the particulate emission limit. With improvements of the burners the concentration of carbon monoxide could be reduced. According to a law of 1983, every coal fired power plant had to install a flue gas desulphurization plant and now the majority produce gypsum which is used in the wall board industry. Due to high landfill costs, dry absorption processes are not cost effective. The latest regulation affected the power plants in 1988 which contains for the first time an emission limit for nitrogen oxide. The technology of choice was the SCR Process, which uses a catalyst material for the reduction of nitrogen oxide. Other technologies were evaluated, but could not be economically realized in a full scale plant for the environmental requirements in Germany.

This paper reviews the German emission regulations and describes the manner in which compliance with emission limits can be reached. Due to the situation in the USA, this paper focuses on the final stage of the environmental protection regulation, the limits on NO_x. Operational results of the past ten years will be presented and the economical impact of the NO_x reduction technology will be discussed.

1. INTRODUCTION

STEAG has been a German independent power producer for over 50 years, owning and operating a total of approximately 5,500 MW of fossil fired boilers. More than 5000 MW of the installed capacity is bituminous coal fired. Figure 1 shows the business divisions of STEAG. All energy related divisions are included in the corporation STEAG AG. AG stands for "Aktiengesellschaft" the German word for "Incorporated".

All of the bituminous coal fired power stations are located in the Ruhr area in the western part of Germany (Figure 2). The main clients for electricity are the German utilities RWE and VEW and the German Railroad "Deutsche Bahn AG".

Almost one third of STEAG's generation capacity is cogeneration. Steam is used to serve industrial clients as well as private households through STEAG's own district heating grid.

The newest power plant is located in the eastern part of Germany. One gas turbine and three residual oil fired boilers are providing electricity, process steam and water to the refinery MIDER, a subsidiary of ELF Aquitaine.

Figure 3 provides some key data of STEAG as well as the international presence. The first power station outside Germany will be in commercial operation in 1999 in Columbia.

2. THE GERMAN EMISSION REGULATIONS

In the past, the German Federal Government together with the State Ministers for the Environmental Protection have passed a package of environmental protection laws which set stringent limits for emissions into the air and water and for waste treatment. Furthermore, noise abatement and protection of landscape are regulated as well as the operation security of the plants (Figure 4). The power plants were mainly affected by the Clean Air Act. Figure 5 summarizes actual emission limits for power plants in Germany. All emission limits are half hour rolling averages.

In order to comply with the emission limits, every power plant is equipped with (Figure 6):

a dust removal system
a desulphurization plant
a NOx removal system

3. DUST REMOVAL SYSTEMS

Since 1974 the power plants in Germany have had to reduce the dust emissions. This was achieved with electrostatic precipitators (ESP). Generally the ESP's are equipped with 3 or 4 fields. Compliance with the dust emission limits could be met even if coal with an ash content of more than 35 % was fired. Taken into account, that downstream of the ESP's further flue gas cleaning devices are installed, the dust emissions are currently less than .0044 gr./cu.ft. Figure 7 shows the development of emission values in STEAG's Power plants since 1980. Noticeable is the reduction in 1988, the year the Flue Gas Desulfurization (FGD) retrofit plants started commercial operation.

4. FLUE GAS DESULFURIZATION PLANTS (FGD)

The German Clean Air Act required the power generators to make the first step of retrofitting FGD plants in 1985. The emission should be less than .33 lb/mmBtu and more than 85% SO_2 removal efficiency. The removal efficiency was in general the dominating parameter; therefore the SO_2 emissions are in the range of .16 to .24 lb/mmBtu, depending on the sulphur content of the fuel. Different technologies for the SO_2 removal are installed in Germany with a clear preference for lime scrubbers (Figure 8). Due to high costs for disposal –DM 1000/t or $ 560 U.S./t at that time- a process was necessary, which produced a sellable by product. Therefore, nearly all plants have FGD's which produce gypsum. This gypsum is used in the wallboard industry and has better properties than natural gypsum. In the beginning, the oxidation process was accomplished outside of the scrubber, meanwhile it is an integrated part of the scrubber. Air is injected into the sump of the lime scrubber. Every FGD system is equipped with a flue gas reheating system. According to federal regulations a minimum temperature at the stack outlet of 162 F must be maintained. Figure 9 provides a typical flow sheet for the wet FGD process. Figure 10 demonstrates the development of the SO_2 emissions in STEAG's plants from 1980 to 1990.

5. NOX REMOVAL SYSTEMS

At the end of the 80's the power plants had to reduce the nitrogen oxide emissions. For the predominant number of units the compliance date was January 1, 1990. Extensive investigations and evaluations had been performed with the result that the technology of choice was the SCR Process for bituminous coal fired power plants. Most of the plants, which fired lignite, could achieve the requirements with primary measures. (Figure 11)

The SCR Process consists of an ammonia injection system, which mixes gaseous ammonia with the flue gas, and a reactor with catalysts, where the ammonia and the NOx react to Nitrogen and water. The main reactions are (Figure 12):

$4\,NO + 4\,NH_3 + O_2 \;\_\; 4\,N_2 + 6H_2O$

$2\,NO_2 + 4NH_3 + O_2 \;\_\; 3N_2 + 6H_2O$

The emission of NOx can be exactly controlled and relates directly to the amount of the injected ammonia. Therefore the actual NOx emissions are only insignificantly less than the required limits. The process itself is simple and the NOx emission target can always be achieved. The minimization of the impact of SCR systems on other components of the plants is the challenge.

Unfortunately the catalyst enhances another chemical reaction on the surface:

$2\,SO_2 + O_2 \;\_\; 2\,SO_3$ (SO_2/SO_3 conversion rate)

The increased SO3 concentration at the outlet of the DeNOx plant can affect the air preheater. The acid due point rises and with the presents of ammonia a sticky salt (NH3HSO4) is formed which can increase the pressure drop of the air preheater if it deposits on the surface of the airheater.

In order to avoid this reaction, the ammonia slip must be limited to less than 3 mg/m3. Therefore a proper design of the SCR system is necessary as well as a frequent monitoring. The required temperature window of 600 to 800 degree F allows three different locations (Figure 13).

The most economic and most common alternative, called "high-dust", is to locate the system between the economizer outlet and airheater inlet. This location usually provides the right temperature window. The "low-dust" alternative is used if a hot ESP is already in operation. In the case space is too restricted to allow a "high-dust" arrangement the SCR can be located downstream ESP and FGD. In this case the catalyst is exposed to the cleanest flue gas possible. However the gas has to be reheated either with gas or oil or steam from the boiler. Therefore it is the least economic solution.

5.1 Operation and Maintenance of SCR Plants

The catalyst's efficiency (activity) decreases by the time due to contamination with flue gas ingredients. The result is an increase of the ammonia slip while the NOx outlet value is a controlled value and constant by time. After a certain time, which depends on catalyst volume, flue gas compositions, etc., the required removal efficiency and a tolerable ammonia slip cannot be met at the same time. A part of the catalyst volume must be added or exchanged. The prediction of this date is essential because catalyst delivery has a lead-time of 3 months or more and the product is relatively expensive.

Three measures (Figure 14) have been established in order to monitor the SCR system.

NH3 concentration of the fly ash

An ash sample of the ESP should be analyzed for NH3. The NH3 adsorbs on the ash particles when passing the air preheater at a certain temperature, which depends on ammonia and SO3 concentration.

The NH3 concentration of the fly ash shows a trend over the time and the catalyst exchange date can be predicted easily.

NOx distribution and ammonia slip measurements

A homogenous NOx distribution downstream of the catalyst is required in order to maximize the catalyst's lifetime. Therefore the NOx concentration has to be measured over the cross section and the ammonia injection system has to be adjusted if necessary.

At selected points, the ammonia concentration should be determined. In order to get a better result and to show a trend, ammonia can also be measured upstream of the final layer.

Activity measurements

A minimum of once a year a catalyst sample should be taken out and the activity should be determined. Usually, the catalyst supplier can perform this measurement. Due to the high uncertainty of the measurements, they can only confirm the status of the SCR system, which has been determined by the NOx and NH3 measurements.

The result is: A catalyst addition should only be considered if all three monitoring tools indicate the necessity. The total reduction of nitrogen oxides was 80% in January 1990 (Figure 15).

5.2 SNCR Experience

STEAG's power plant Herne, Unit 4, which was erected in 1988/89 was a NOx demonstration project equipped with low NOx burners and a SNCR system. The German Department of Research financed this project.

A highly sophisticated NH3 injection and control system was installed (Figure 16). The reagent was anhydrous ammonia. However, it was not possible to achieve the required NOx reduction efficiency of 50% with a reasonable ammonia slip. During the design phase the decision was made to install additionally a SCR system. Finally, after three years of extensive testing, including hybrid tests of SCR and SNCR the project was stopped. A very important reason besides the technological problems of the SCR was the better economics of the SCR.

5.3 Cost of NOx reduction technology

Figure 17 presents a cost example for one of STEAG's SCR plants. The boiler is a 710 MW wall fired dry ash boiler. The uncontrolled NOx is .5lb/mmBtu and the removal efficiency 70%. Wide varieties of coals domestic as well as import are fired. The average sulfur content is 1%. The SCR system was commissioned in 1989 and operated 53,000 hours as of today. The first year catalyst replacement is the average of the total catalyst consumption over 8 years divided by the operating time in years. The total cost for the NOx removal to the required .14lb/mmBtu is $ 1.88 U.S. per MWh or 1.88 mills/kWh. The total capital cost for this plant was $ 57/kW including all direct and indirect costs. The same plant could be built today for approximately 30 % less (Figure 18). The two main reasons are a much higher experience level and a significant catalyst development.

5.4 Conclusion

Since 1989 STEAG operates all types of SCR systems (high dust, low dust, tail end) with all types of catalysts (honeycomb, plate) from the major catalyst suppliers (KW Huels, BASF, Siemens, Hitachi, Cormetech). There has never been an outage of a power plant which has been caused by the SCR system. All emissions were in compliance over the entire time with no exception. The SCR systems do not affect the salability of the by products gypsum and ash. STEAG sells three million metric tons of fly ash and tons of gypsum per year.

Business Divisions of STEAG AG

STEAG AG

- Power Generation
- Power International
- By-Product Management
- District Heating

STEAG Industrie AG

- Building Technology
- Process Technology in the Clean-room
- Services

Figure 1

STEAG - Power Plant Locations

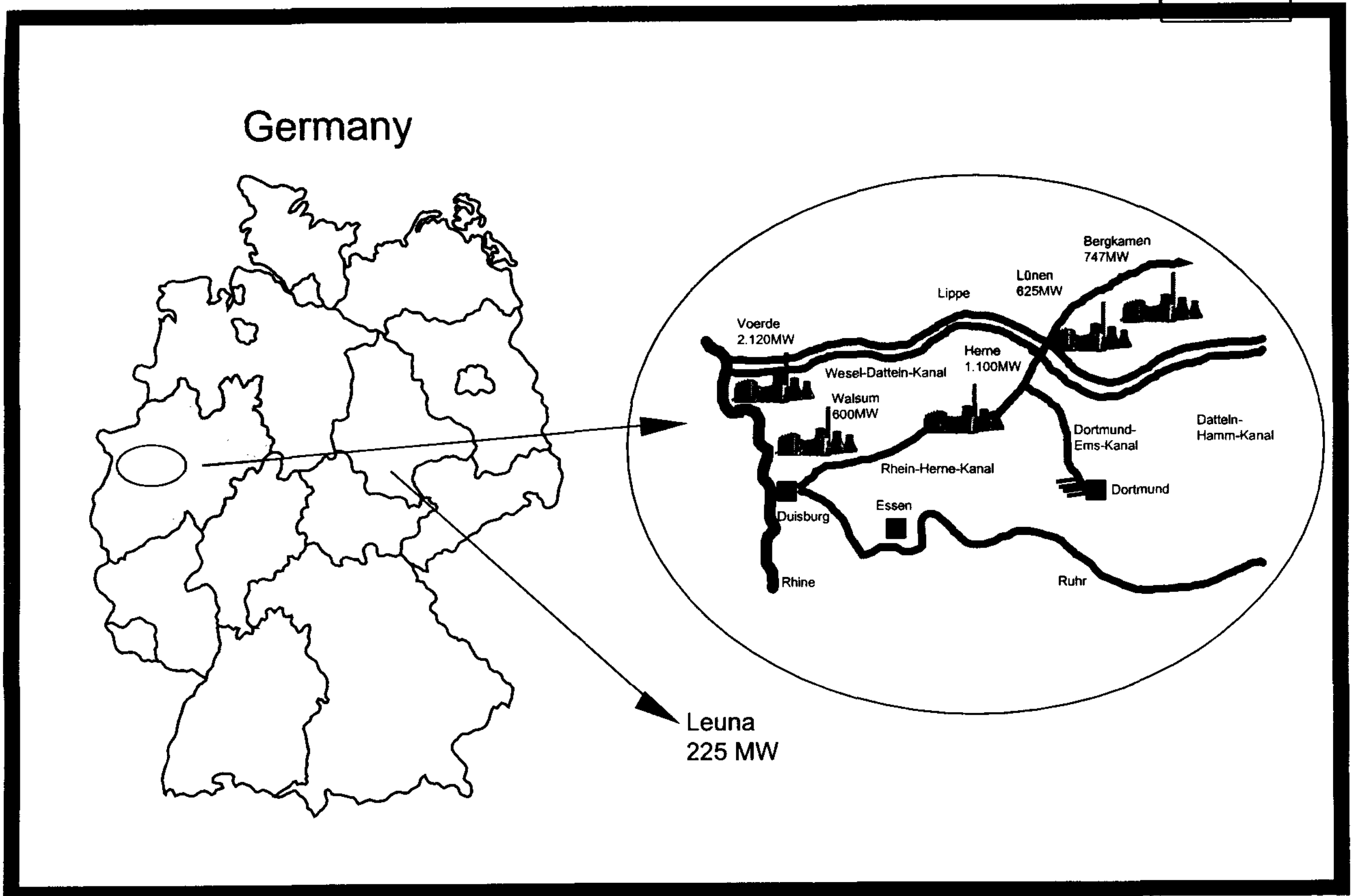
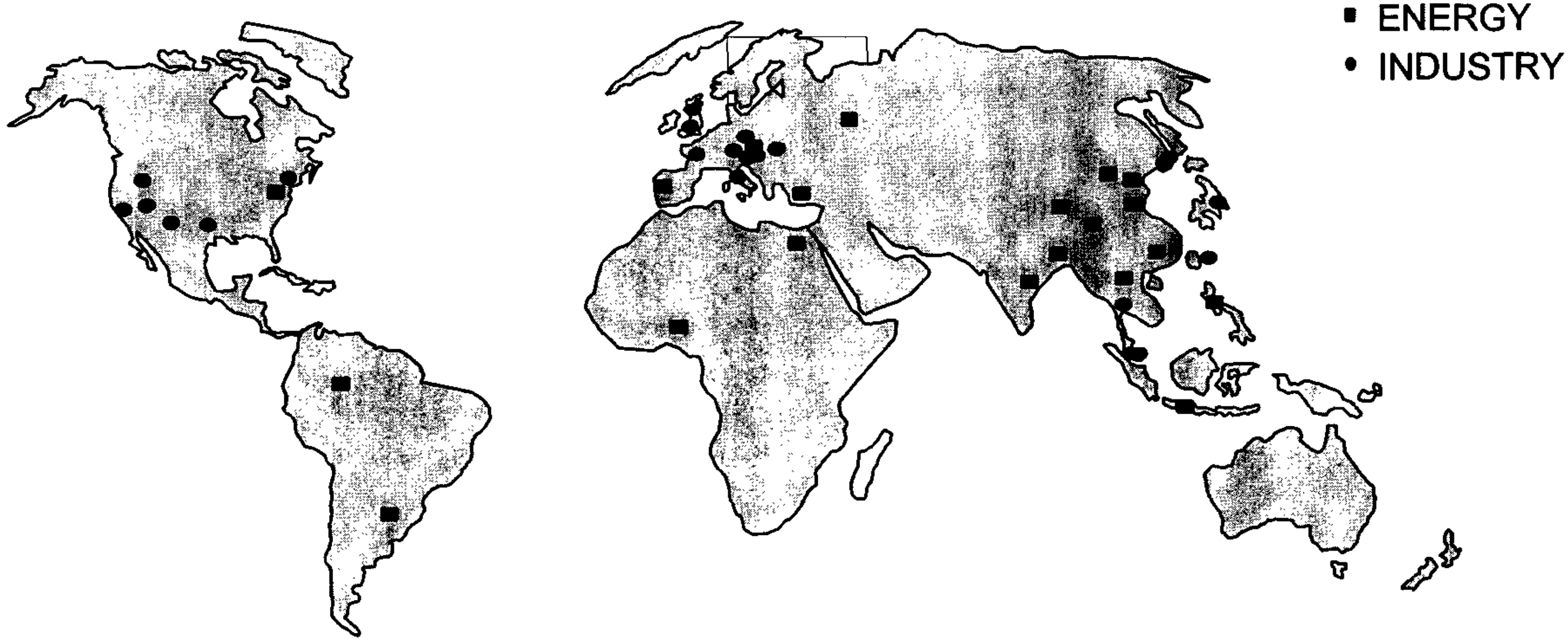


Figure 2

World-wide Presence of Steag's Corporate Domains ENERGY and INDUSTRY



Key Data		1996	Shareholders	
Sales	Mio $ U.S.	1.40	RAG AG	71.1 %
Investment	Mio $ U.S.	0.25	GfE (VEBA/RWE)	25.9 %
Employees		4,851	Others	3.0 %

Figure 3

German Emission Regulations

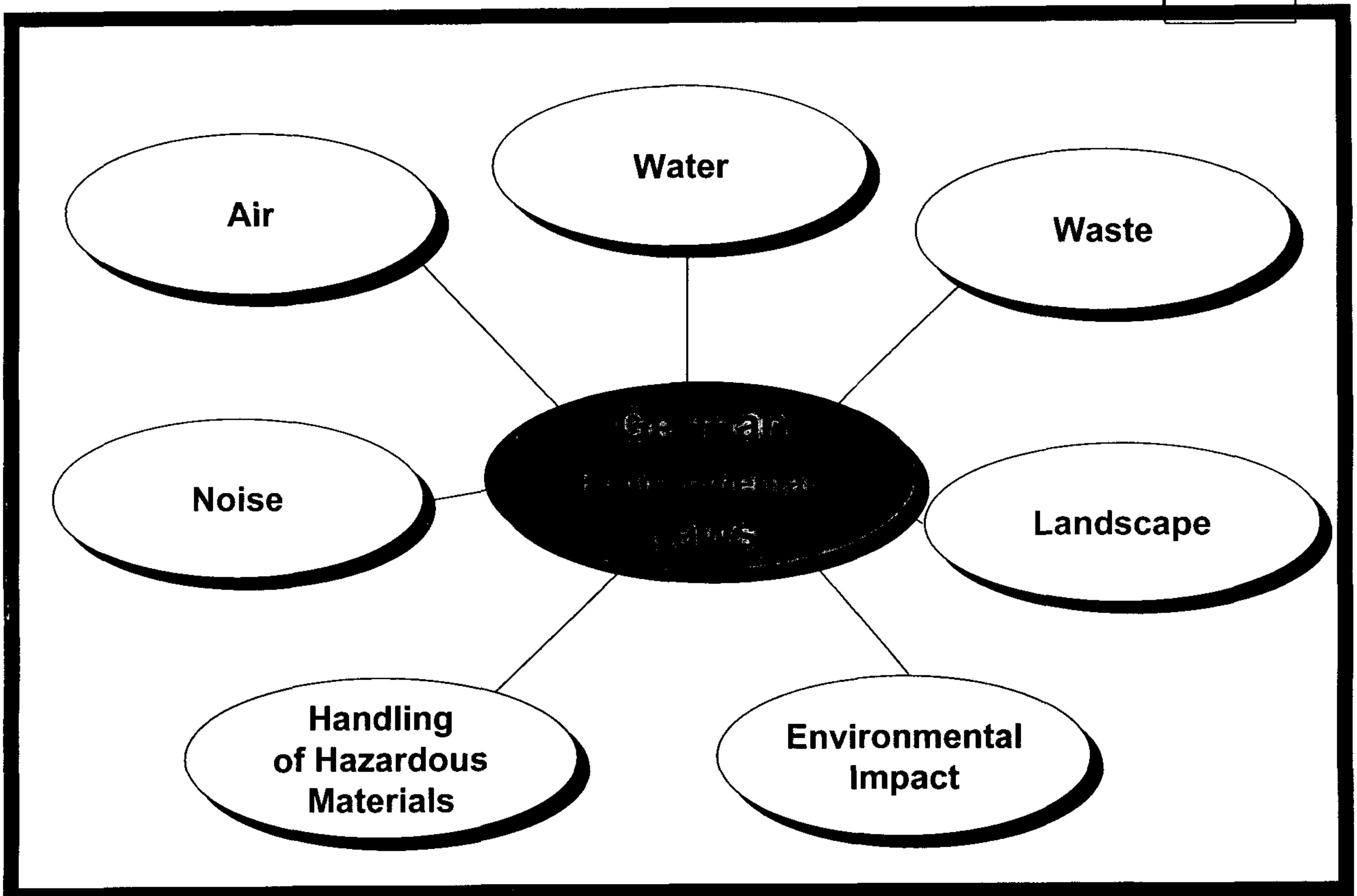


Figure 4

Emission Limits for Air Pollutants

Substance	Solid Fuel $\geq$ 50 MW th.	Liquid Fuel $\geq$ 50 MW th.	Gaseous Fuel $\geq$ 50 MW th.	Unit
Dust	0.22	0.22	0.22	gr./cu.ft.
Carbon Monoxide	210	145	85	PPM
Nitrogen Oxides	0.14	0.10	0.06	lb./mmBtu
Sulfur Oxides	.33	.33	.002	lb./mmBtu
	or	or		
	>85	>85		%Removal
Chlorine	67	20	-	PPM
Fluorine	18	6	-	PPM

Figure 5

Typical Flue Gas Cleaning System in German Power Stations

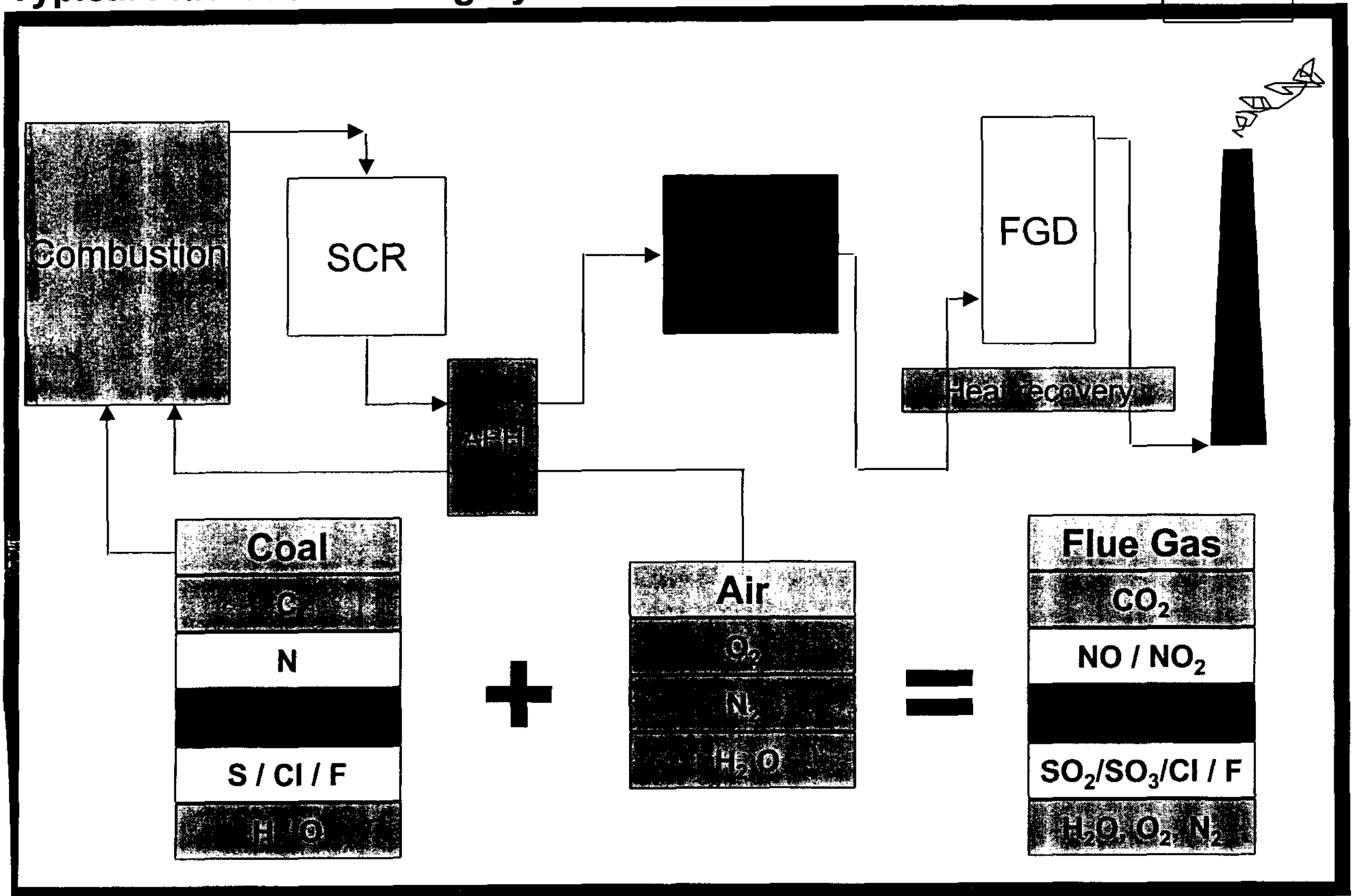
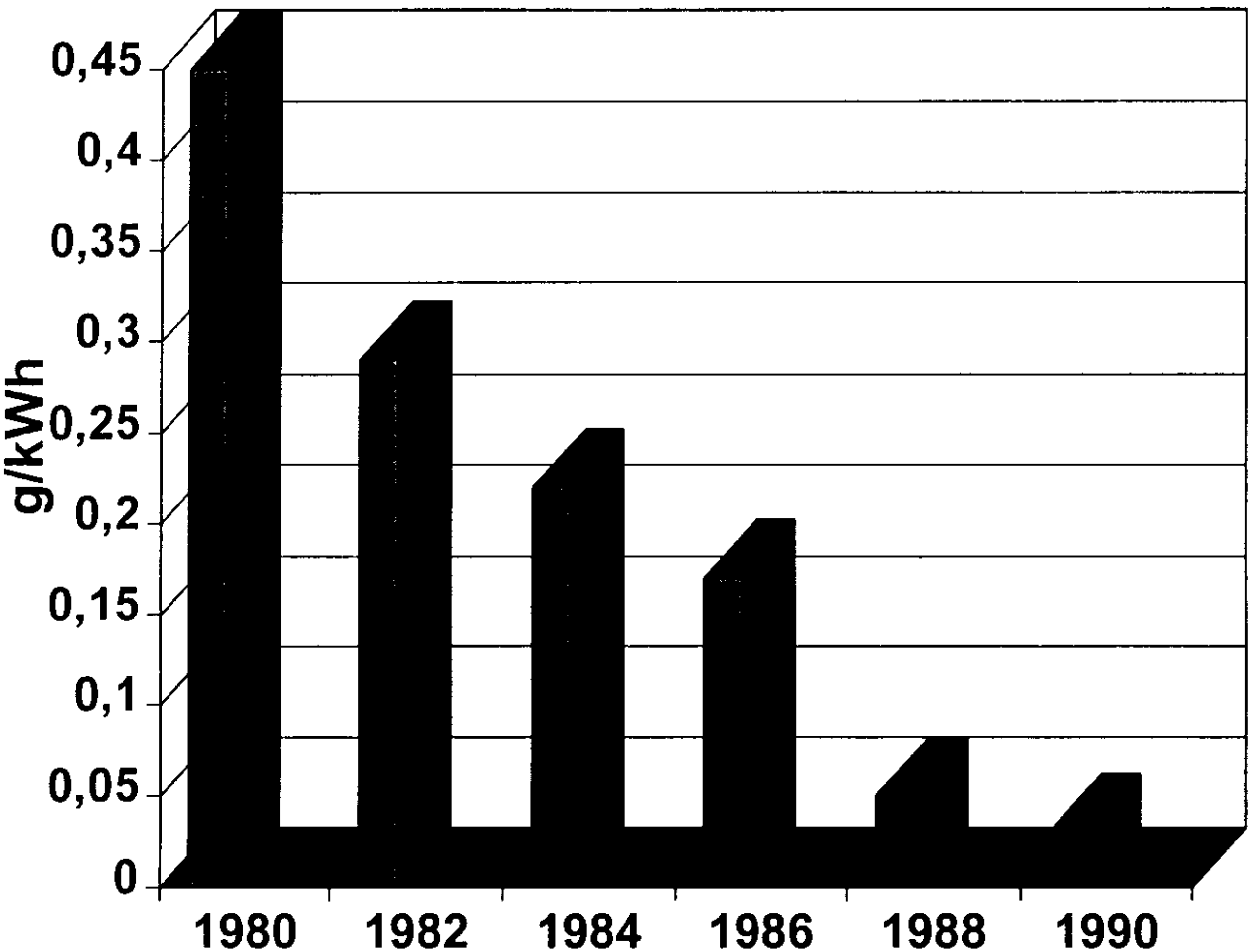


Figure 6

Dust Emissions in STEAG´s Power Station



1 g/kWh =
.145 gr./cu.ft.

Figure 7

Survey of Desulphurization Processes

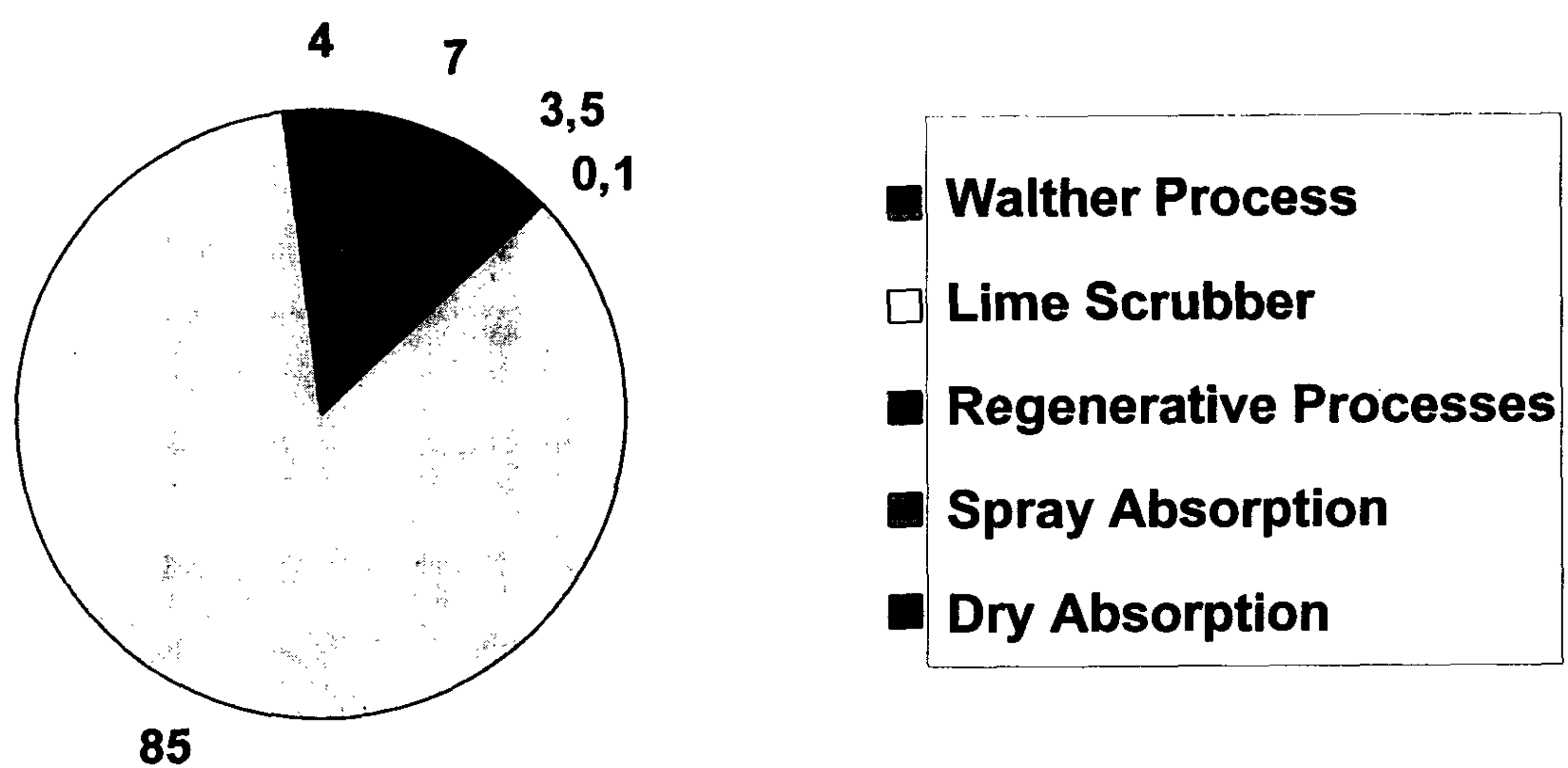


Figure 8

Lime Scrubber with Gypsum Production

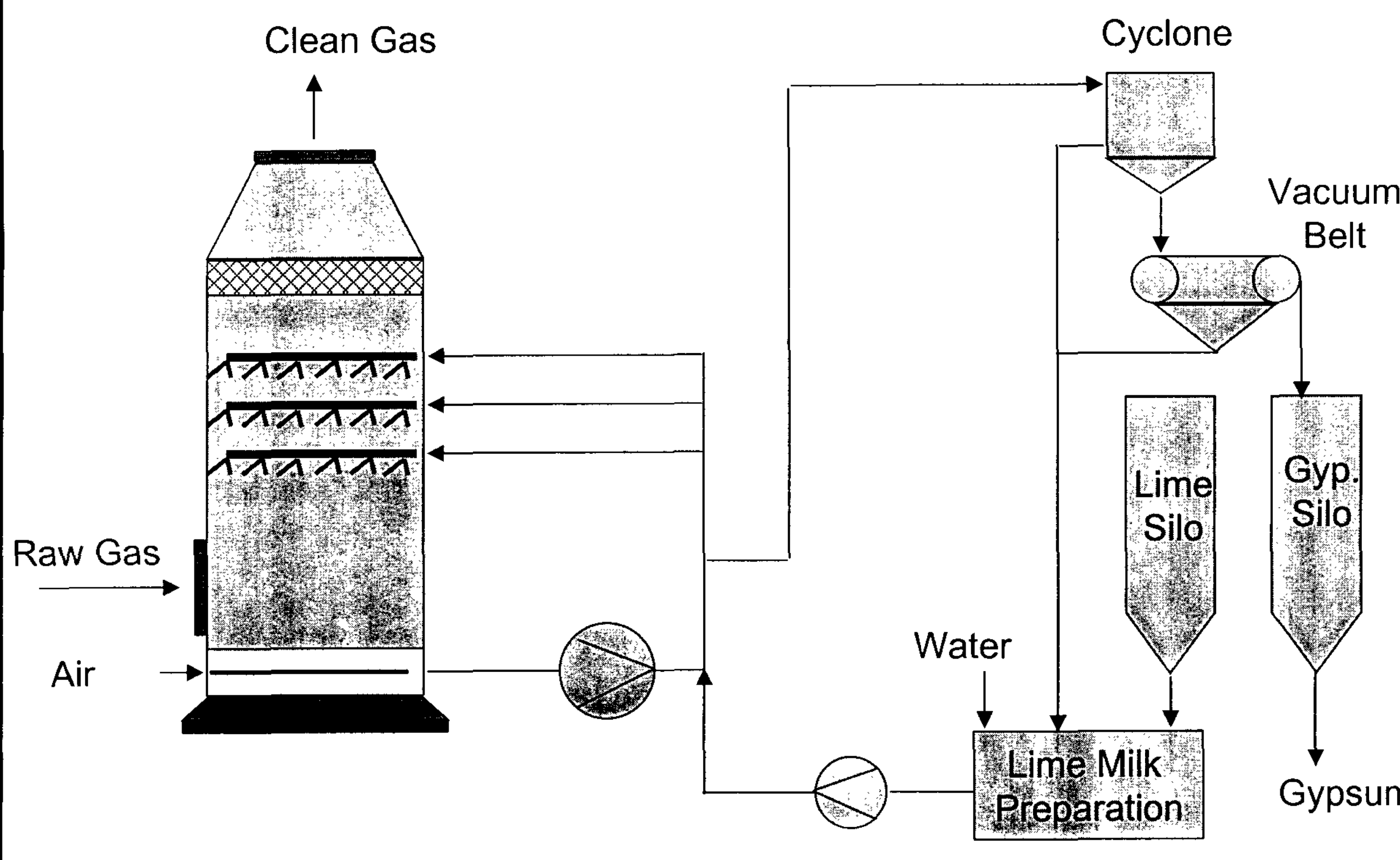
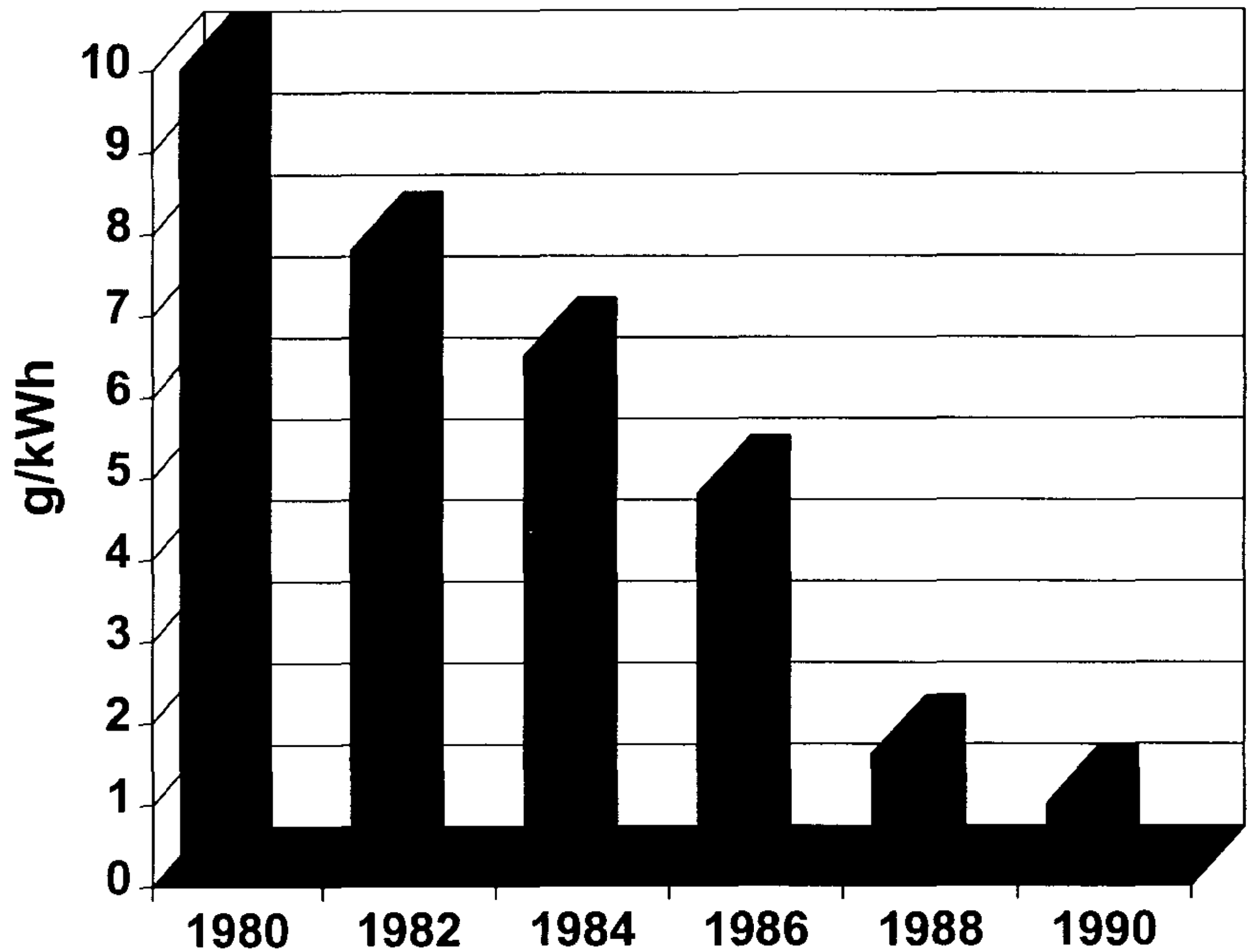


Figure 9

SO_2-Emissions in STEAG´s Power Stations



1 g/kWh SO_2 =
0,271lb./mmBtu

Figure 10

Survey of No_x-reduction Systems

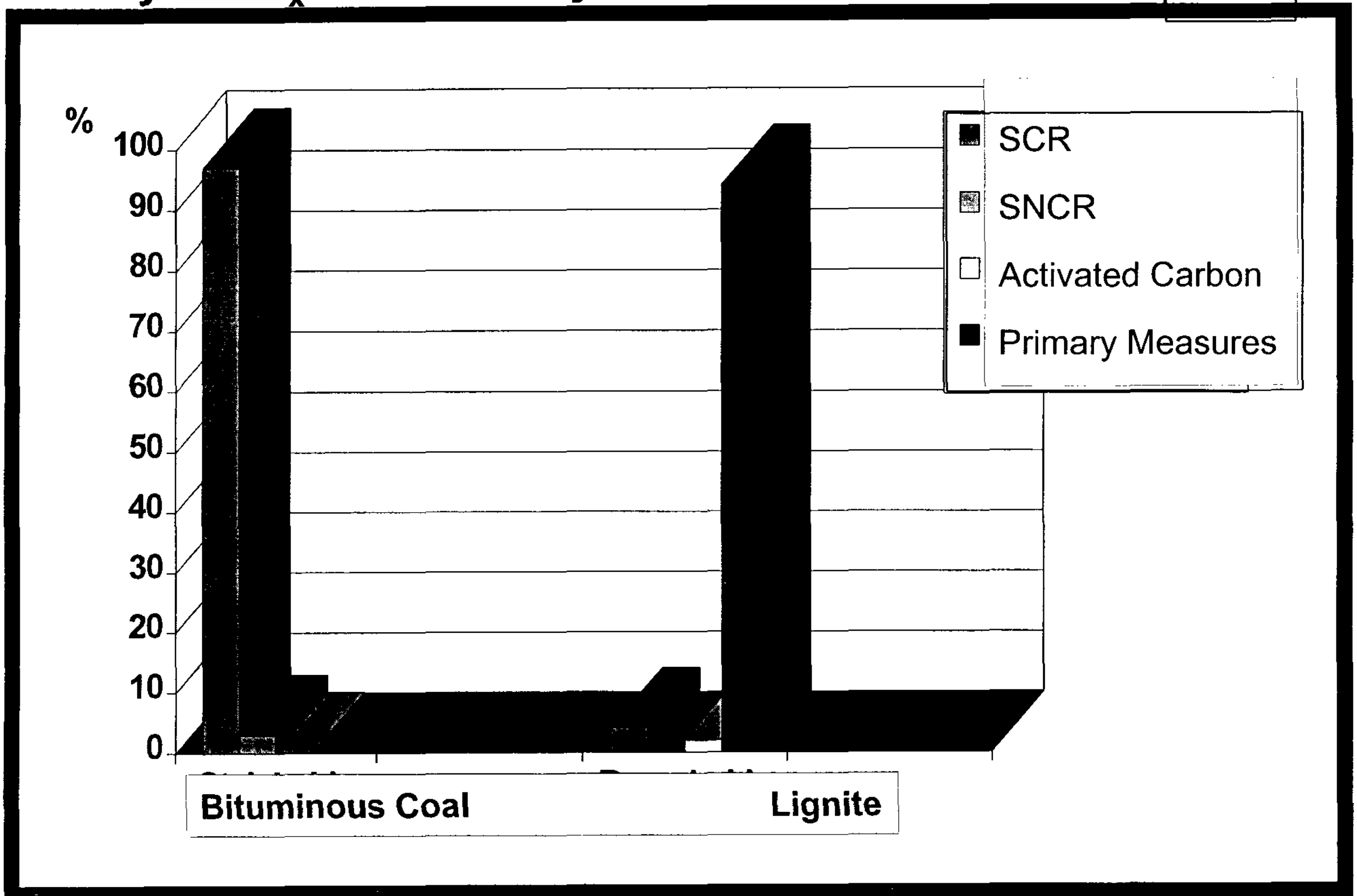


Figure 11

Chemical Reactions

Main Reactions

$$4\,NO + 4\,NH_3 + O_2 \xrightarrow[\text{Temperature}]{\text{Catalyst}} 4\,N_2 + 6\,H_2O$$

$$2\,NO_2 + 4\,NH_3 + O_2 \xrightarrow[\text{Temperature}]{\text{Catalyst}} 3\,N_2 + 6\,H_2O$$

Secondary Reactions

$$2\,SO_2 + O_2 \xrightarrow[\text{Temperature}]{\text{Catalyst}} 2\,SO_3 \quad (\,SO_2\,/\,SO_3\text{ - Conversion}\,)$$

$$NH_3 + SO_2 + H_2O \xrightarrow[200°\text{-}250°]{} NH_4HSO_4 \quad (\text{ Ammoniumbisulfat })$$

Figure 12

Applications of SCR-Systems

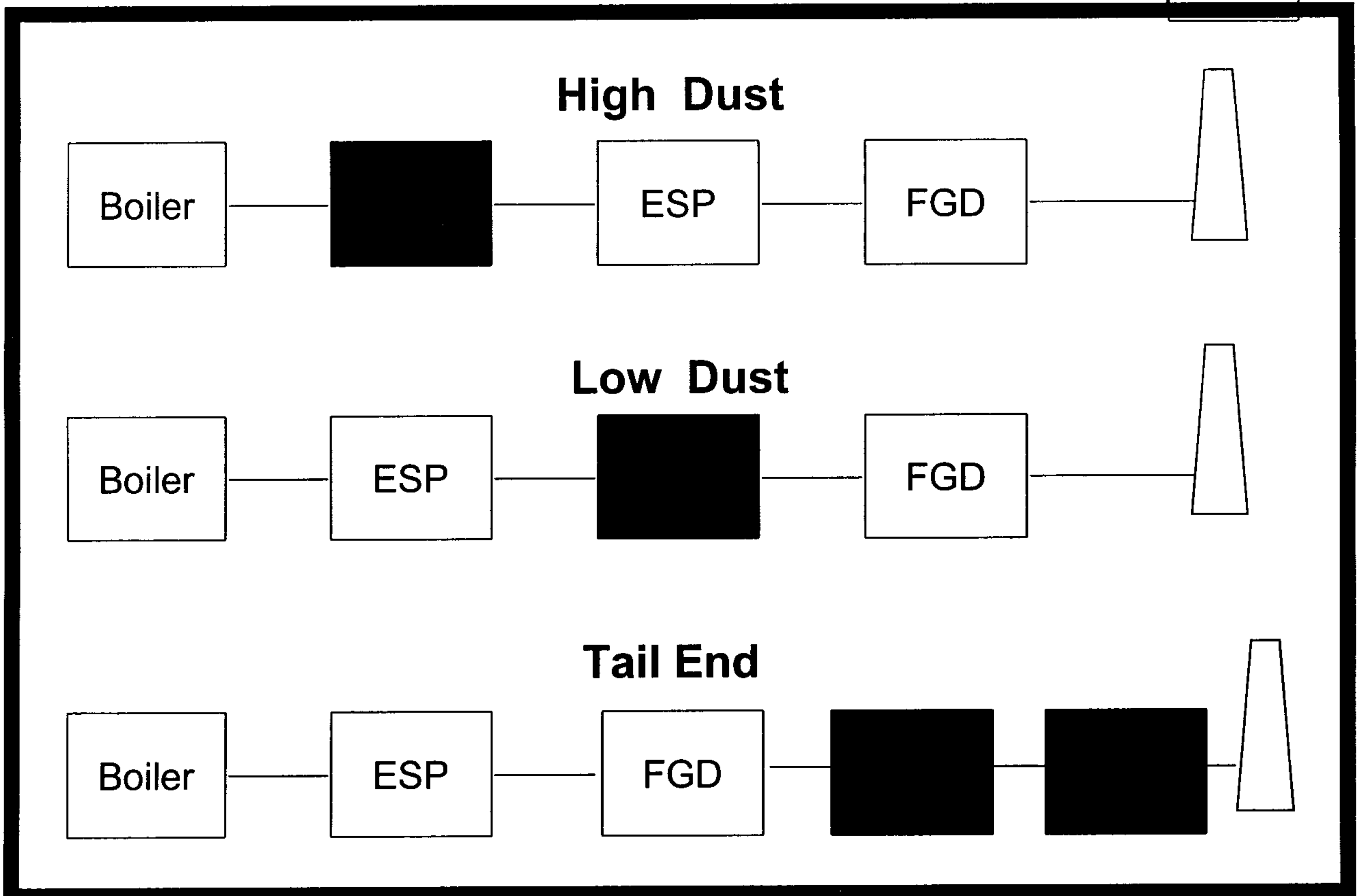


Figure 13

Operation and Maintenance of SCR Plants

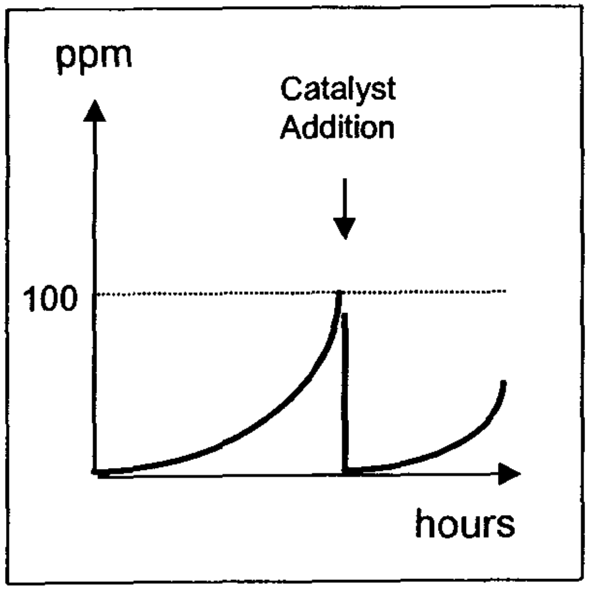
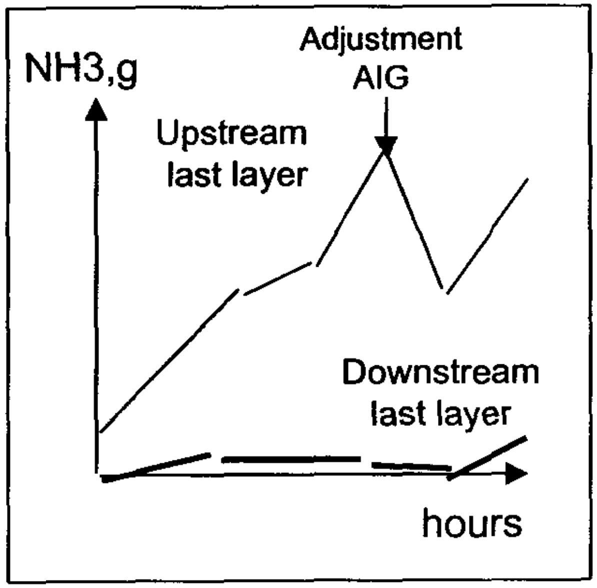
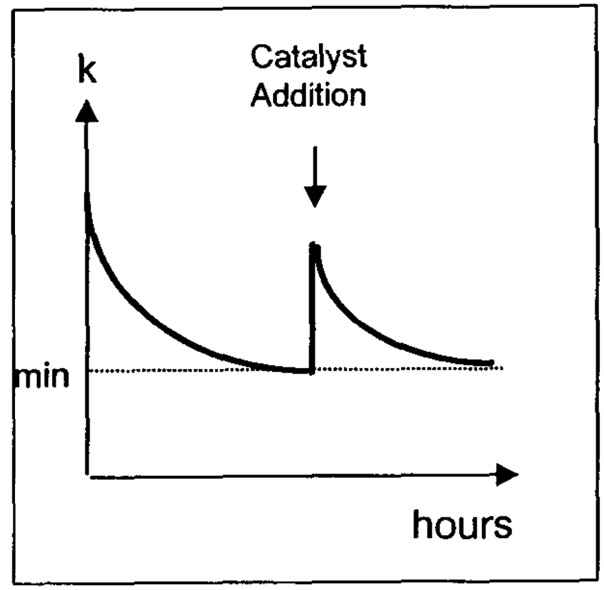
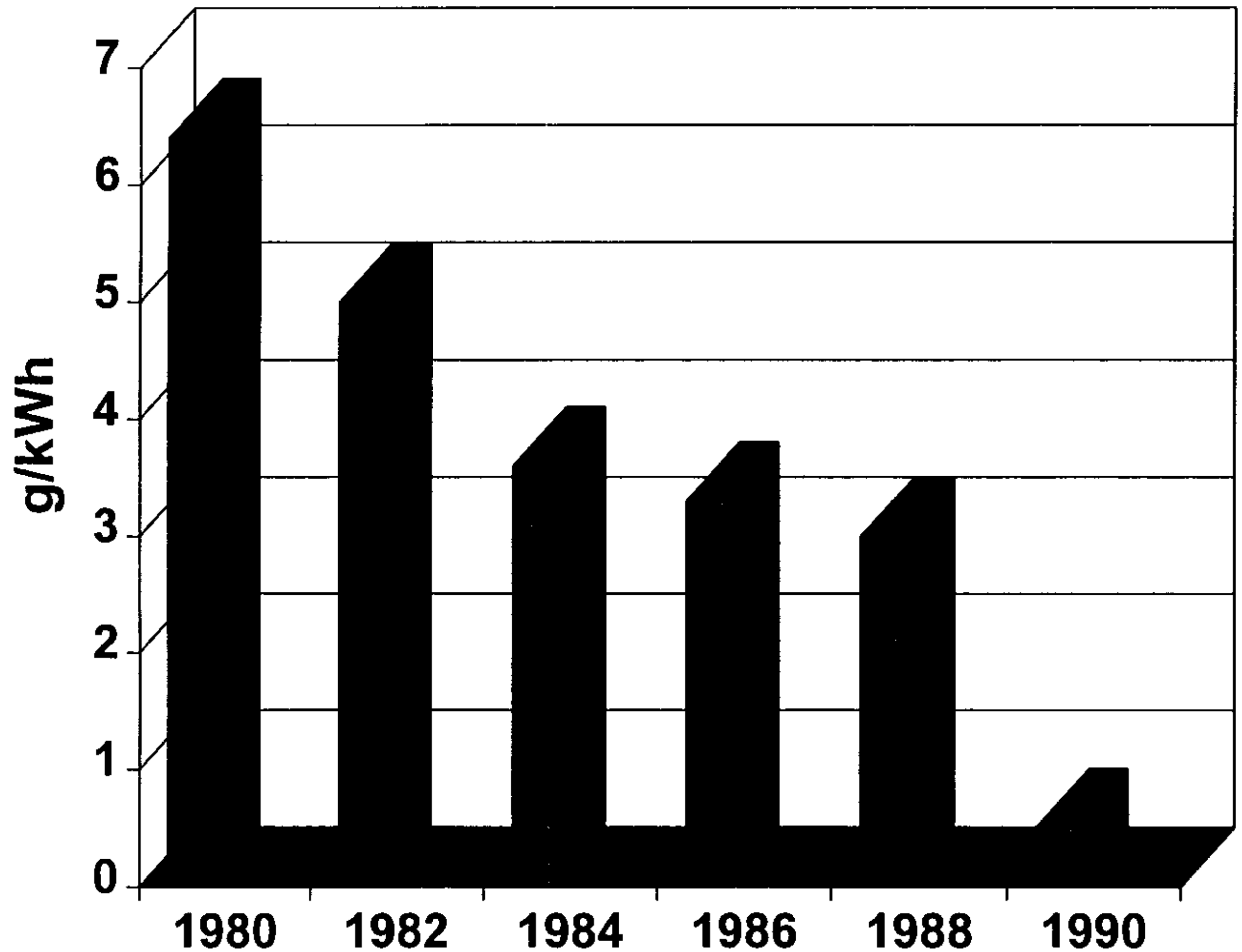
NH_3 concentration on fly ash	NOx distribution and NH_3 measurements	catalyst activity measurements
		
Operator	**Third Party**	**Catalyst Supplier**
Measurements: daily / weekly	Measurements: once or twice a year	Measurements: once a year

Figure 14

NO_X-Emissions in STEAG´s Power Stations



1 g/kWh NO_x =
0.271 lb./mmBtu

Figure 15

SNCR System

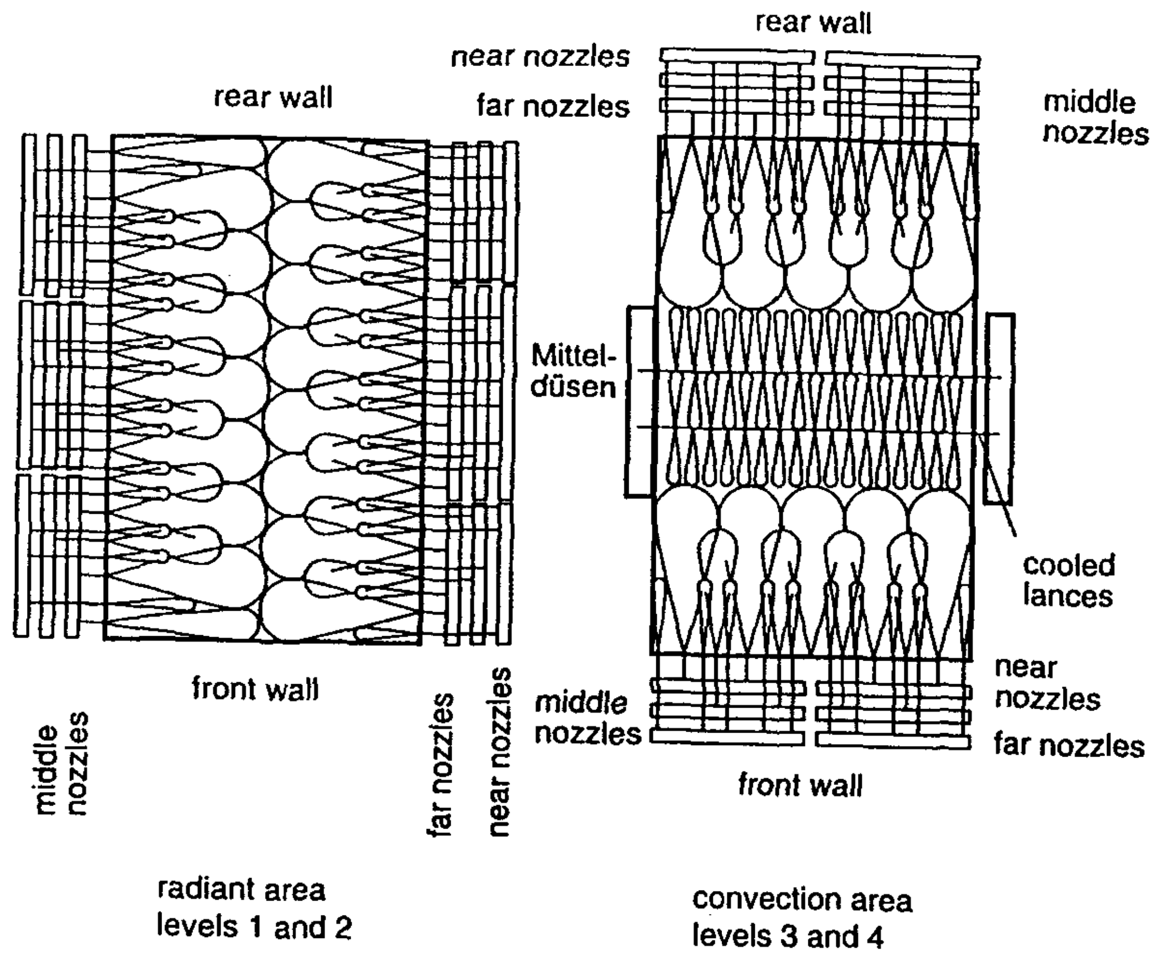


Figure 16

Total SCR System Costs

Total SCR Cost = 57 $/kW

- Includes all direct and indirect costs
- Includes ammonia storage
- Actual design basis would reduce catalyst by 30 %
  -- 5 to 6 $/kw impact

Figure 17

Total SCR System Costs

Design Parameters

Plant size	710 MW
ΔNOx removed	0,5 $^{Lb.}/_{mmBtu}$
Operating hours	7,000 $^{h}/_{yr.}$

First Year Costs

		US$/yr.
Fixed charges on capital investment (15 %)		6,070,500
Maintenance (2 % of capital investment)		809,400
Catalyst replacement (14,000 $/m³)		955,000
Ammonia ($ 250 / ton)		1,019,000
Energy ($ 30 / MWh)		500,000
Total		9,353,900
Specific costs	$/MWh	1,88

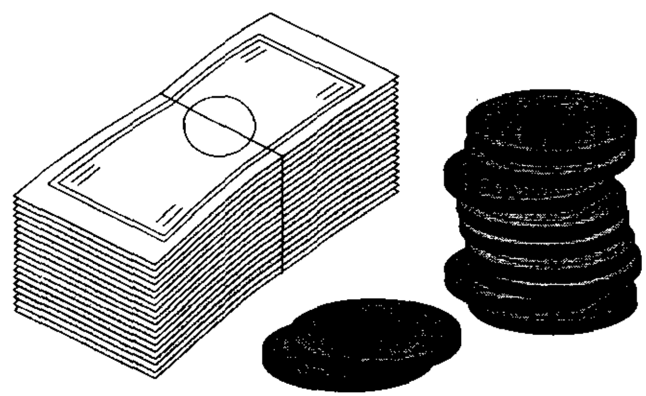
Figure 18

Cost of Environmental Compliance

STEAG has spent a total of

700 Million US$

for environmental protection,



sells 3,000,000 tons of fly ash and gypsum per year,
meets 0.14 lb./mmBtu NO_x and 0.27 lb./mmBtu SO_2

Figure 19

THE IMPLICATIONS OF EMISSIONS TRADING ON POLICY AND TECHNOLOGY CHOICES

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PANEL SESSION 2

Issue 2: Domestic Competitive
Pressures for CCTs

IMPLICATIONS OF STATE UTILITY RESTRUCTURING FOR CLEAN COAL TECHNOLOGY USE

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ABSTRACT

Electric utility restructuring activities are now underway in every state. This paper reviews state legislative activities and their implications for Clean Coal Technology use. While state restructuring laws are conceptually and functionally diverse, many include environmental quality provisions. However, these laws do not typically recognize the importance of coal in the nation's energy mix, nor do they foster coal-based research and development initiatives.

1. INTRODUCTION

I'm pleased to be a part of this distinguished panel. I'm going to speak briefly today about the implications of state-level electric utility restructuring for the development and use of Clean Coal Technologies.

In simple terms, the Federal Energy Policy Act of 1992 allowed states to decide whether to authorize retail competition in electricity markets. Today, the process of structural and regulatory change is well underway all across the country. Earlier this year, the Edison Electric Institute reported that 14 states, representing approximately 40% of the population of the US, had already passed restructuring laws and every state in the union is moving forward with restructuring to some extent.

The EEI report also noted -- and I found in my discussions with state officials -- that restructuring is conceptually and functionally different in every state, depending on a wide variety of factors. These factors include the current rate structure, the mix of fuel resources, social programs, stranded cost issues, and environmental policies.

The process of electric utility restructuring is not proceeding in a straightforward manner. In fact, as the nation's largest and most capital-intensive industry changes fundamentally from a regulated, restricted monopoly to a competitive market, it's moving relatively quickly and relatively inconsistently. Furthermore, it is moving without much thoughtful, systematic discussion of policy options or how the impending changes will impact the nation and its overall economy.

Layered on the inconsistencies of state actions are the regulatory uncertainties that we've heard so much about from other conference speakers. The result is that it is difficult to predict just how Clean Coal Technologies will fare in restructuring. But there are a few relevant trends to be noted in what's happened thus far.

2. TRENDS IN RESTRUCTURING

The first trend is that **states are using utility deregulation to drive environmental quality initiatives.**

This trend addresses concerns that restructuring will maximize the use of cheaper, older, higher-polluting plants to keep costs low in the competitive environment. It should be noted here that the Energy Department does not project major increases in pollution as a result of restructuring. In fact, DOE has predicted that a competitive market for power will stimulate greater efficiency in energy production to maximize the margin between costs and sales. In this scenario, pollution will decrease as a result of restructuring.

The trend toward environmental quality initiatives is a predominant one: Of the 14 or 15 states where restructuring laws have passed, 9 have explicitly included some type of environmental provision in the legislation.

At the minimal level, the environmental provision consists of a simple disclosure requirement. Both Illinois and California, for example, have adopted provisions mandating disclosure of fuel sources and emissions levels to consumers.

At the next level, some states have incorporated provisions that actively promote energy sources that are perceived to be "green." New York's legislation, for example, includes a "net metering" provision that allows customers who produce electricity from solar cells to receive a meter credit for that energy.

Another approach that several states have pursued is to include specific requirements for "green power," generally identified as solar and renewables, excluding hydropower and municipal waste. Nevada, for example, has established a renewable energy resources portfolio requiring sellers of electricity to offer 1/2 of 1% from solar and 1/2 of 1% from other renewable sources. The Massachusetts law also requires at least 1% of the electricity sold in the state to be generated from renewable resources. And, in Maine, retail suppliers of electricity must have 30% of their power generation portfolios in renewables.

Solar, wind and geothermal power currently account for only about 3% of total US generation. However, there are a lot of interests with money on the table betting that green energy is what people will want.

Public opinion polls have consistently shown that consumers will pay somewhat more for energy they judge to be environmentally sound. In July of 1997, the Wall Street Journal reported on the cost differential that consumers would accept for green power. The article noted that of 4745 households in a Massachusetts pilot project, 1457 signed up for offers billed as more environmentally sound at an average cost of 16% higher. The offer included a pledge not to obtain power from coal-burning plants. In Colorado, about 3000 residential customers and 6 large energy users agreed to pay a 35% premium on their utility bills to fund the construction of 13 wind turbines.

While some residential customers and even businesses, might be willing to pay significantly more for green power, cost considerations will generally rule in a competitive market. Accordingly, some of the environmental initiatives focus not on promoting green power but on making coal and other traditional fuels more expensive to use.

One of the major ideas coming into currency is that of a carbon tax -- a concept already in use in northern Europe and gaining some momentum here. In Minnesota, for example, restructuring plans under discussion include a carbon tax to offset a property tax reduction. An Oregon-based organization called Northwest Environment Watch is also promoting a carbon tax as part of deregulation. Northwest Environment Watch estimates that a tax of $100 a ton on carbon dioxide would increase the wholesale price of coal by 49% and of natural gas by 14%.

Some of the conference speakers have provided very close estimates of the cost differentials between Clean Coal Technologies and competing technologies. Obviously, any additive cost factor would be a great disincentive for Clean Coal technology use for new capacity additions.

The second trend that can be noted in a review of state legislation is that **the role that Clean Coal Technologies can play in achieving environmental quality goals has not been an explicit consideration in restructuring**. I looked carefully for some positive, affirmative provisions that would perhaps recognize the benefits of Clean Coal Technologies or even the importance of coal to the nation's energy mix, but coal is essentially invisible in this legislation.

Only one state -- Illinois -- has included funding for coal projects in deregulation. Our legislation includes a fee on electric and gas bills that forms a dedicated funding stream divided equally among coal development projects, renewable energy projects and low-income energy assistance. It's a relatively small amount of money and it's currently being focused on cost-reducing improvements to the mining infrastructure in Illinois, and not on R&D or technology deployment.

And that brings me to a final trend that I noted in reviewing state legislation -- I won't elaborate on it because it's already been mentioned by other speakers in other contexts -- **these laws are not oriented toward innovation or technology advancement**. The few laws that include research and development provisions (Montana and California) are focused on renewable resources.

3. CHALLENGES

The role that Clean Coal Technologies can play in the nation's energy mix should be part of state-level utility restructuring decisions. The industry has a good story to tell, with many accomplishments. As Secretary Godley said yesterday, those advocating the use of these technologies must make themselves heard at the state level, as well as in the national and international arenas. George Preston began this conference eloquently yesterday with the statement that technology drives change -- and that might be true in a perfect world. In the real world, the agents of change are sometimes political agendas, or popular enthusiasms, or highly interpretive scientific journalism, or even El Nino. All of these are playing out in the restructuring debates, and we are going to have to work hard to get our message heard above the background noise.

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Trigen Energy Corporation

Environmental Issues in Federal Deregulation Legislation

Gilbert Waldman

Director of Development

Trigen Energy Corporation

Mission Statement

Provide heating, cooling and electricity with half the fuel and half the pollution of conventional generation

Trigen, the leading thermal sciences company in North America, develops, owns and operates commercial energy systems. Trigen uses its expertise in thermal engineering and proprietary cogeneration processes to convert fuel to various forms of thermal energy and electricity at more efficient conversion rates than conventional processes. Trigen combines heat and power generation, producing electricity as a by-product, for use in its facilities and for sale to customers. Compare this approach to conventional utility power plants that generate electricity alone. Adoption of combined heat and power on a broad scale can double fuel conversion efficiency, halve fuel consumption, dramatically lower energy prices, eliminate the need for large-scale transmission lines, substations and feeders, and reduce emissions of NO_x, SO_2, and CO_2.

Trigen Capacities

- **Production Capacities**
  - **3,576 MWth steam & hot water**
  - **352 MWe electric**
  - **306 MWth chilling**
- **Distribution Capacities**
  - **203 km steam & hot water pipe**
  - **17 km chilled water pipe**
  - **42k m^3 chilled water storage**

Trigen serves more than 1,500 customers with energy produced at 31 plants in 22 locations, including industrial plants, electric utilities, commercial and office buildings, government buildings, colleges and universities, hospitals, residential complexes and hotels.

The Energy Business is Changing

- **Electric Restructuring is underway throughout the world**
- **Environmental Regulations and Initiatives are putting increased pressure on the fuel conversion sector**
- **Technology is being employed in new and different ways**
- **Changes create opportunities for profit**

The electric utility industry is undergoing major changes that will affect all energy consumers. Privatization and deregulation of utility companies is taking place throughout the world. The Federal Energy Regulatory Commission (FERC) has established the framework and rules for competition in the wholesale electric market in the United States. Individual states are in various stages of activity, or lack thereof, in establishing competition in retail markets.

Air quality requirements are becoming increasingly stringent. For example, EPA has initiated rule making to establish emission standards for toxic air pollutants from combustion units, including industrial boilers. Similarly, the 1990 Amendments to the Clean Air Act require EPA to conduct a study of mercury from utility boilers. The EPA's report on the study, which was submitted to Congress in December 1997, stopped short of recommending specific emission reduction, but did identify a number of health and environmental impacts from mercury deposition.

The market place will drive technology development, rather than vice versa. Open access of electric retail markets and the resulting competition will drive manufacturers towards more efficient and lower cost means of producing power. Environmental constraints will force manufacturers to respond to increasingly stringent emission standards. For example, dry low NO_x burners and selective catalytic reduction (SCR), which were considered experimental technologies a few years ago, are common specification requirements for gas turbine manufacturers.

Structural Market Changes

Electric Monopoly:

- **Captive electricity customer**
- **Backup power from local utility only**
- **Price = regulated rate of return without environmental credit for efficiency**
- **Alternative generation effectively blocked**
- **Artificial barriers to competition**

Retail Access:

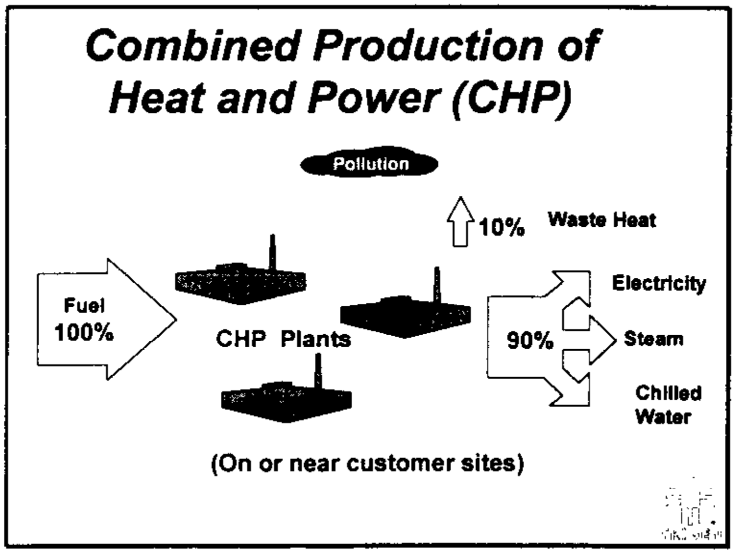
- **Buy electricity from anyone**
- **Backup from market**
- **Price = most efficient = environmental benefits**
- **Alternative generation often best option**
- **Market determines price without stranded cost recovery, third party retail laws, and other barriers**

Although the original purposes behind electricity regulation made sense at the time, and utilities did a good job of providing reliable, universal serve, regulation and monopoly protection have allowed the power industry to maintain a separation of the production of electricity and thermal energy. Building a plant to produce only electricity and another separate plant to produce heat is inherently inefficient. With full retail access, market forces will drive energy suppliers to greater efficiency. Utilities with a regulated rate of return do not have the incentive to reduce costs that are recoverable from rate payers. Likewise, they have every incentive to maintain their monopolies and discourage competition. Utilities have eliminated a large number of potential industrial combined heat and power projects through onerous back-up rates, and state laws prohibiting on site retail electricity sales. More recently, these same utilities have lobbied state governments successfully for "deregulation" that includes transition charges or exit fees to recover stranded costs. In reality, imposition of transition charges on alternative suppliers of electricity, which can include owner/operators of on site heat and power facilities, serves to maintain the status quo.

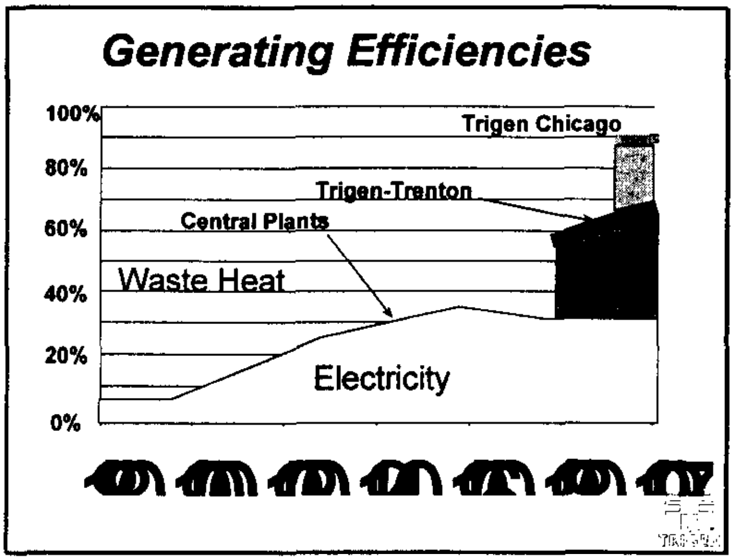
Why Distributed Generation?

- **Central generation wastes two-thirds of fuel**
- **Electric production near end user can recover heat**
- **Highly efficient - 55% efficiency for combined cycle up to 91% for combined heat and power**
- **Factory built equipment from 5 kW to 150 MW**

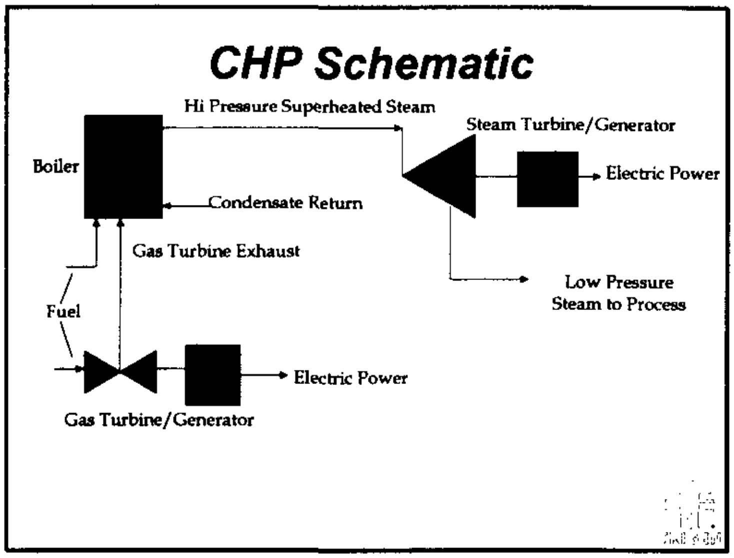
Distributed generation is the deployment of power generation equipment close to the end user. Distributed generation can be accomplished using any fuel and a variety of available technologies. Although some people talk about distributed generation as electric only, the most economic distributed generation consists primarily of small combined heat and power plants serving industrials, hospitals, universities, and commercial establishments. The inherent advantage of distributed generation over central station power is the elimination of electric transmission and only moderate use of local electric distribution services.



Combined heat and power converts about 85% of the heat that is wasted in typical utility central electric generating stations to useful thermal energy in the form of process and/or heating steam, hot water, and absorption chilling. Efficient use of fuel is a simple way to reduce pollution and conserve natural resources. Burning less fuel automatically reduces emissions proportionately.



This diagram shows the evolution of central plant electric generation technology, and corresponding heat rate improvements, compared to combined heat and power. Even with the most efficient advanced combined cycle power generation, recovery of heat that is otherwise lost to the condenser represents an opportunity for overall heat rate improvement.



Industrial applications for combined heat and power typically consist of a gas turbine exhausting to a heat recovery steam generator (HRSG) or boiler. The difference between a boiler and a HRSG is that a boiler includes register burners, while a HRSG utilizes heat from turbine exhaust with or without duct firing. In the case of a boiler, the oxygen rich hot gas turbine exhaust acts as a supply of air, or "repowering", for firing coal, natural gas or oil. High pressure steam, which is typically at 650 psig/750 F for industrial applications, enters a back pressure turbine for additional production of power. The turbine discharges steam for heating or industrial process use. The combination of a gas turbine with a fully fired HRSG or repowered boiler supplying steam to a back pressure steam turbine is the most efficient CHP configuration. This approach can be applied as a retrofit to existing coal boilers to reduce emissions, and improve overall efficiency and cost of operations.

Environmental Initiatives Affecting Energy

- **Recent regional NOx transport study recommends substantial energy sector reductions**
- **Recent New Source Performance Standards Proposal targets boiler emissions**
- **National CO2 reduction strategies will inevitably target the energy sector looking for cost effective solutions**

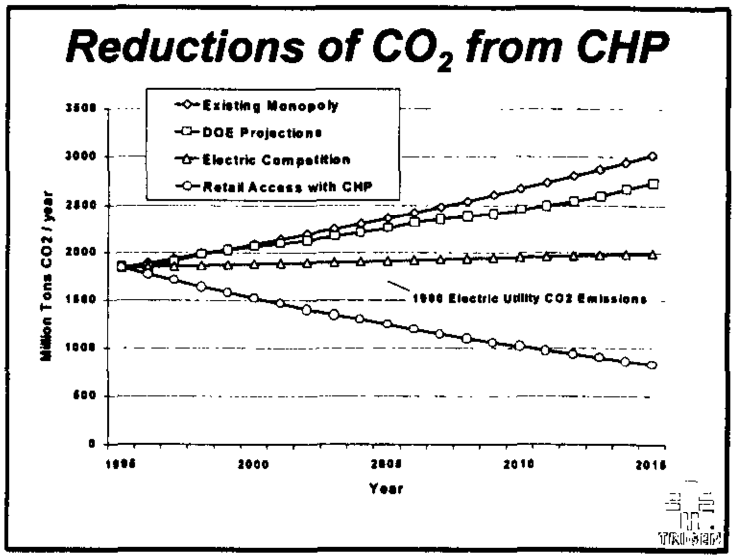
EPA recently proposed revised ozone National Ambient Air Quality Standards (NAAQS), which will ultimately trigger the designation of new nonattainment areas. Thus, sources in the new ozone nonattainment areas may be required to achieve additional VOC and NO_x reductions.

EPA has proposed a rule to require twenty-two eastern states to update their state implementation plans (SIPS) to reduce NO_x emissions. Utility boilers could potentially be subject to NOx reductions of up to 85% and industrial boilers up to 70% reductions from 1990 levels.

EPA also recently issued a revised standard for fine particulate NAAQS, including $PM_{2.5}$, although the agency does not anticipate that states will submit SIPS for meeting the standard until between the years 2005 to 2008. In the meantime, boiler owners will be required to collect emissions monitoring data.

The Kyoto Global Warming Treaty would require the implementation of greenhouse gas (primarily CO_2) emission reductions. If the United States ratifies this treaty, there may be new greenhouse gas emissions reductions requirements.

None of the trends described above bodes well for owners of existing coal fired boilers. The simplest and most economic approach to reducing emissions from coal fired boilers is to retrofit these facilities with combined heat and power systems that either completely or partially substitute natural gas fuel for coal. It is important to owners of all types of power generation facilities that the wording of environmental regulations provides incentives for efficiency.



The best tool for emissions reduction is not to burn the fuel in the first place. This diagram shows the potential reduction of greenhouse gas emissions from the efficiency of combined heat and power. Other pollutants will be reduced similarly.

Im plications

- **Energy sourcing will become complex**
- **Opportunities to save significantly, but will require significant investment**
- **Technology will surge in ways to convert fuel to useful energy**
- **Regional cost differences will fade**
- **Thermally matched combined heat and power will set competitive price targets**

Commercial and industrial consumers will be faced with additional choices as electric power sales are unbundled into generation, transmission, distribution and ancillary services components. Energy professionals will have to evaluate the makeup of competitive offerings to select the best proposals from a wide variety of marketers, energy service companies, utilities, and other suppliers. Nevertheless, the added investment in analysis will be well rewarded through the cost savings resulting from a competitive market. Investments in technology and equipment can be deferred to specialized energy providers, such as Trigen Energy Corporation, allowing the industrial or commercial establishment to invest their capital in their core businesses. Integration of transmission systems and market forces will ultimately erase artificial cost differences among regions of the country. Dispersed combined heat and power systems will be accepted as the standard for highly efficient and cost effective generation of electricity and thermal energy.

Changes in Technology

- **Improved gas turbines for CHP**
  - **Increased firing temperatures of gas turbines - increased efficiency**
  - **Improved controls and lower emissions**
  - **Lower capital costs**
- **Energy Storage**
- **Back pressure steam turbines replace pressure reducing valves**
- **Integration of CHP into existing coal and gas fired steam plants**

Advancements in technology are allowing owners of combined heat and power facilities to become more efficient and profitable. For example, chilled water storage, such as Trigen has installed at McCormick Place in Chicago, stores cold water that is produced at night and discharges it to meet daylight peak cooling loads. Fewer chillers are required to meet peak demands and they can be operated continuously, thereby maximizing production efficiency. Replacement of pressure reducing valves with back pressure steam turbines is another way of reducing fuel consumption with a fast investment payback.

Trigen's View of the Future

- **On-site energy is produced through high efficiency CHP and dispersed generation**
- **Barriers to competition are removed from retail electricity sales**
- **Efficiency and emissions reductions are rewarded**
- **Government inducement for all above.**

The opportunities for combined heat and power are huge and can have a significant impact on the competitiveness of the United States economy. With full retail access, market forces will drive all energy professionals to greater efficiency. In a free market environment many firms will find that distributed combined heat and power is the low cost solution.

To encourage combined heat and power generation with twice the efficiency and half the pollution of central power, combined heat and power plants should be exempt from stranded cost payments or exit fees in the transition to a deregulated retail electricity market. This formulation will send a strong signal to the market to build more efficient combined heat and power plants, and thus lower emissions in accordance with the trend to more stringent environmental standards.

It is critical that the regulatory jurisdiction between the federal and state governments be defined. Rules for national competition should be consistent. This is a particular concern in those states where established traditional utilities have disproportionate leverage with state regulators. Federal oversight is needed to ensure that a truly competitive environment is established by a date certain.

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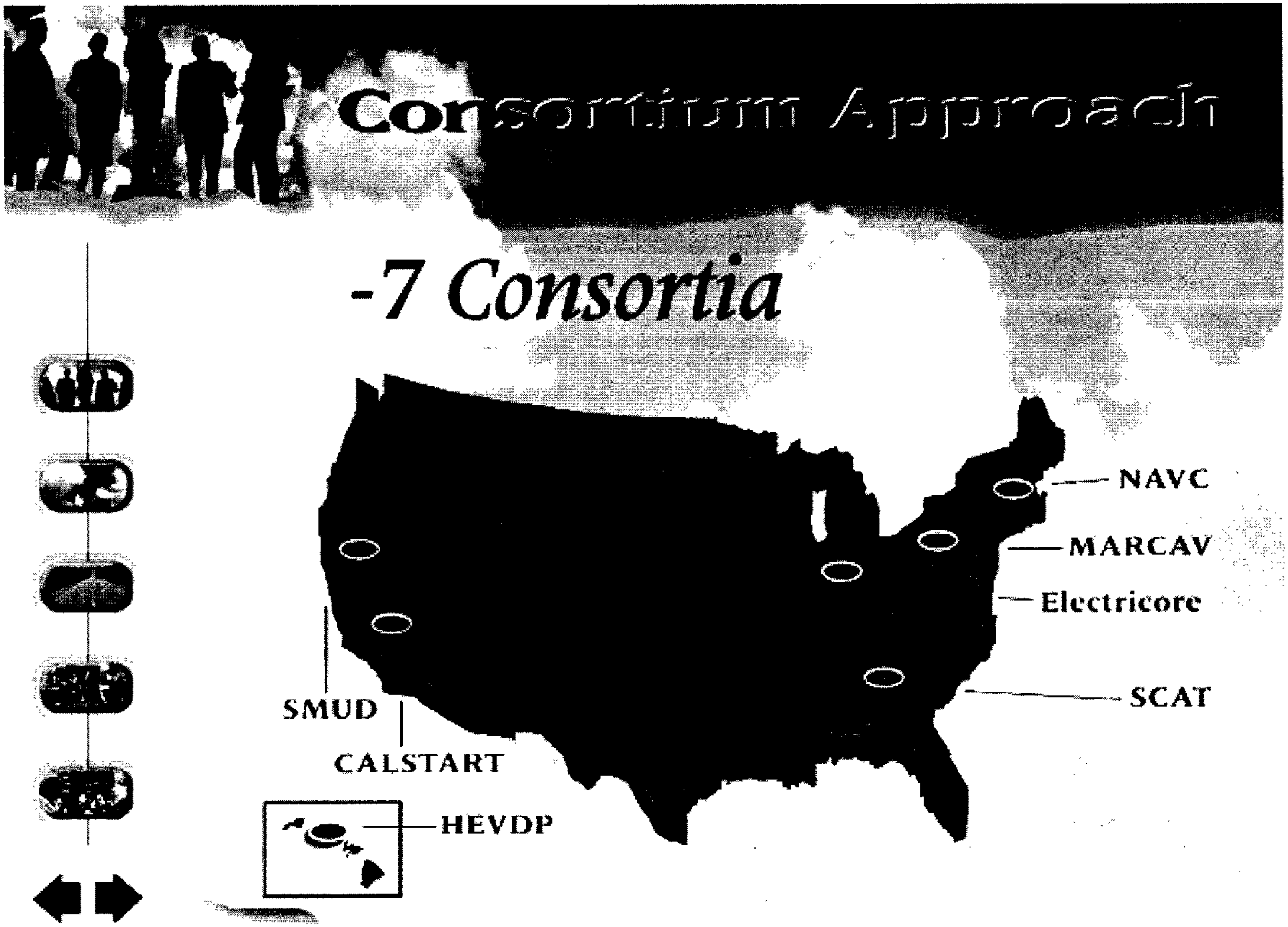
Why SCAT?
Consortium Approach
Members
Research Portfolio
Education
Public Affairs
SCAT
SOUTHERN
COALITION
FOR ADVANCED
TRANSPORTATION


Consortium Approach


Consortium Approach
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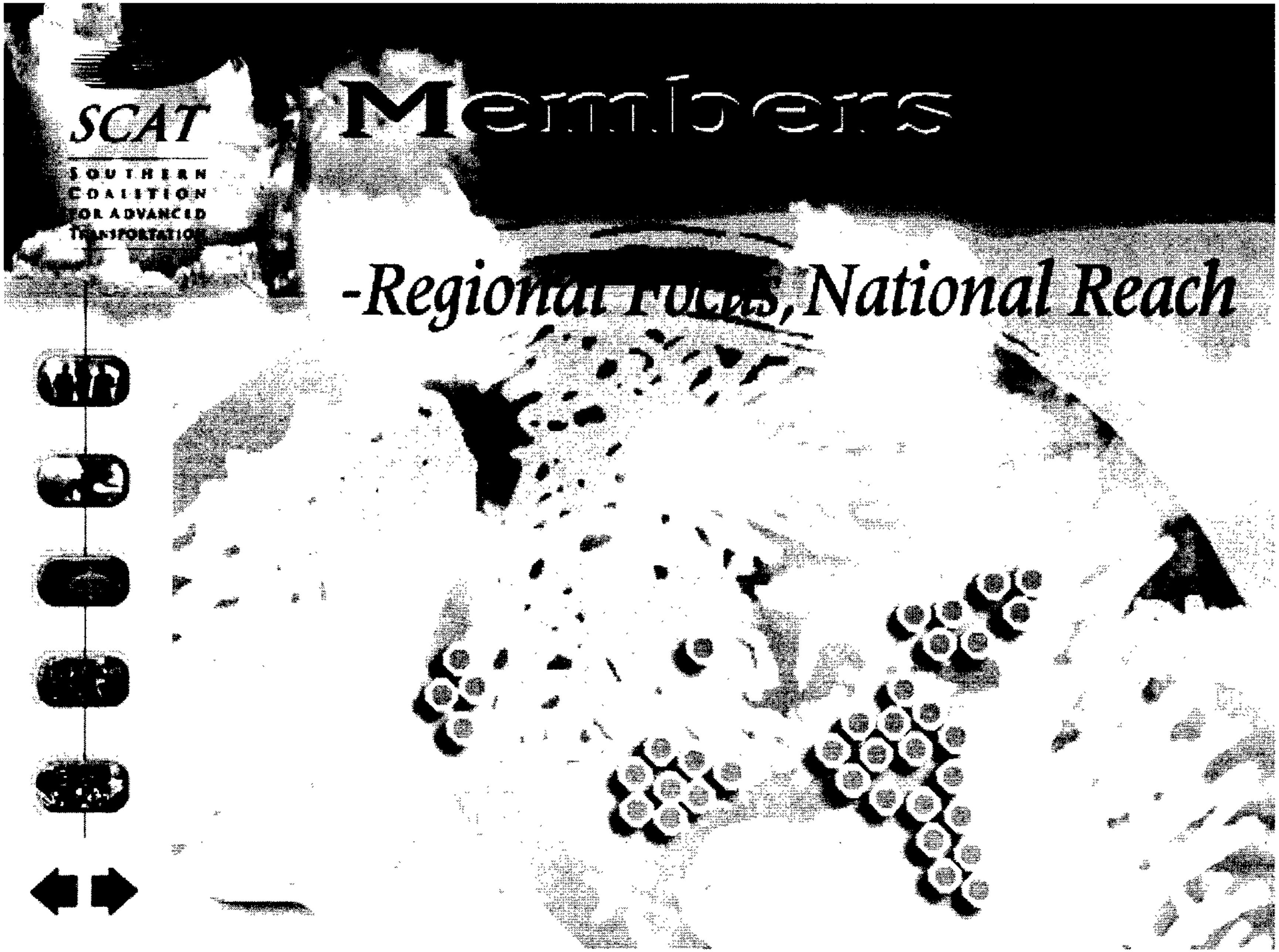
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Members
-Regional Focus, National Reach

SCAT

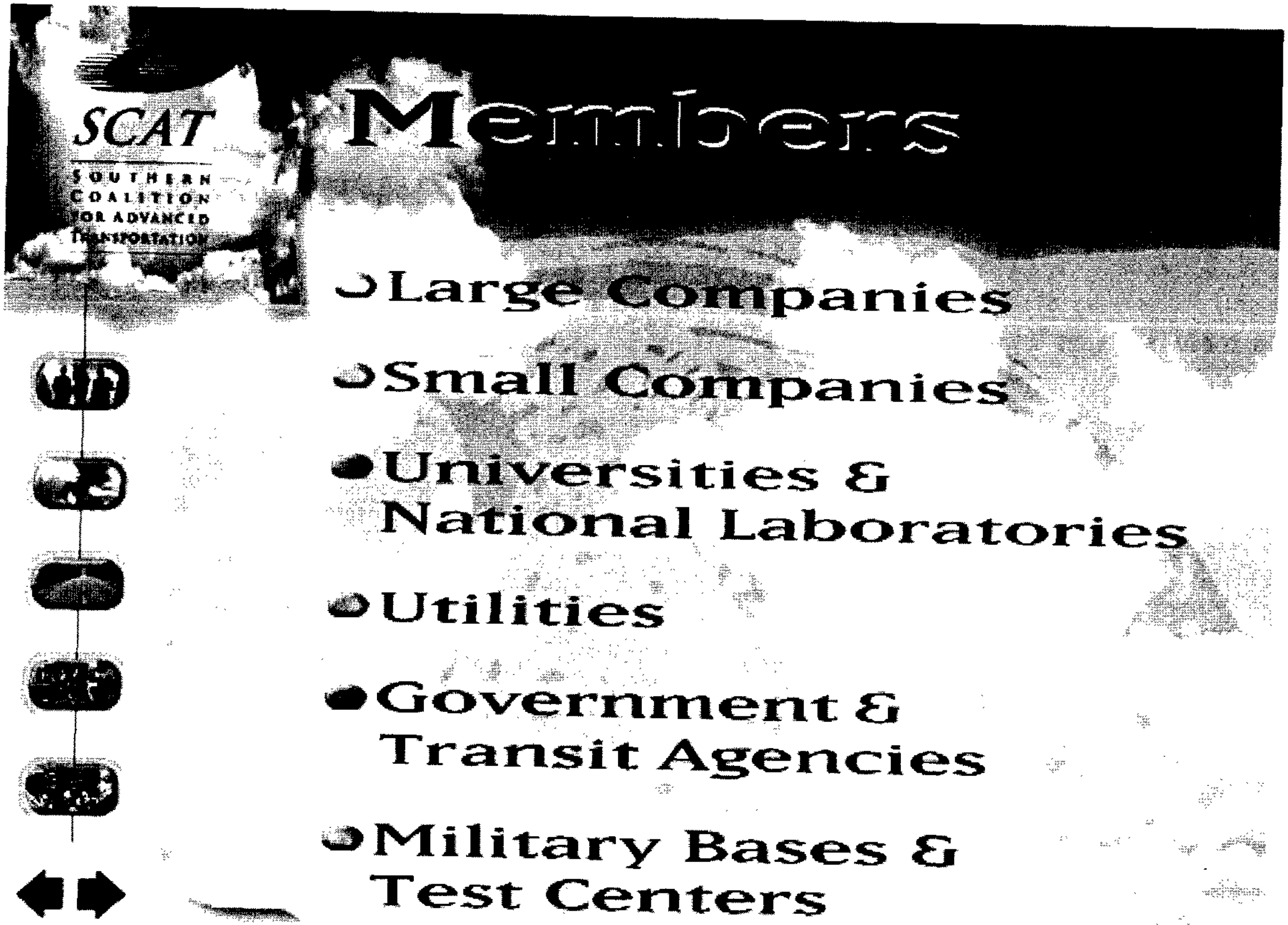
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION

Members

-Mission (What we are and what we do)

As a non-profit technology consortium of public and private institutions, SCAT provides mechanisms for businesses, government, and academia to pool resources in areas ranging from electric and hybrid electric transportation technology research and demonstration to direct market stimulation.


SCAT
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION
Members
-Vision (What we want to be)
SCAT will be a leader in facilitating the rapid development, commercialization, public understanding and acceptance of advanced transportation technologies for global markets.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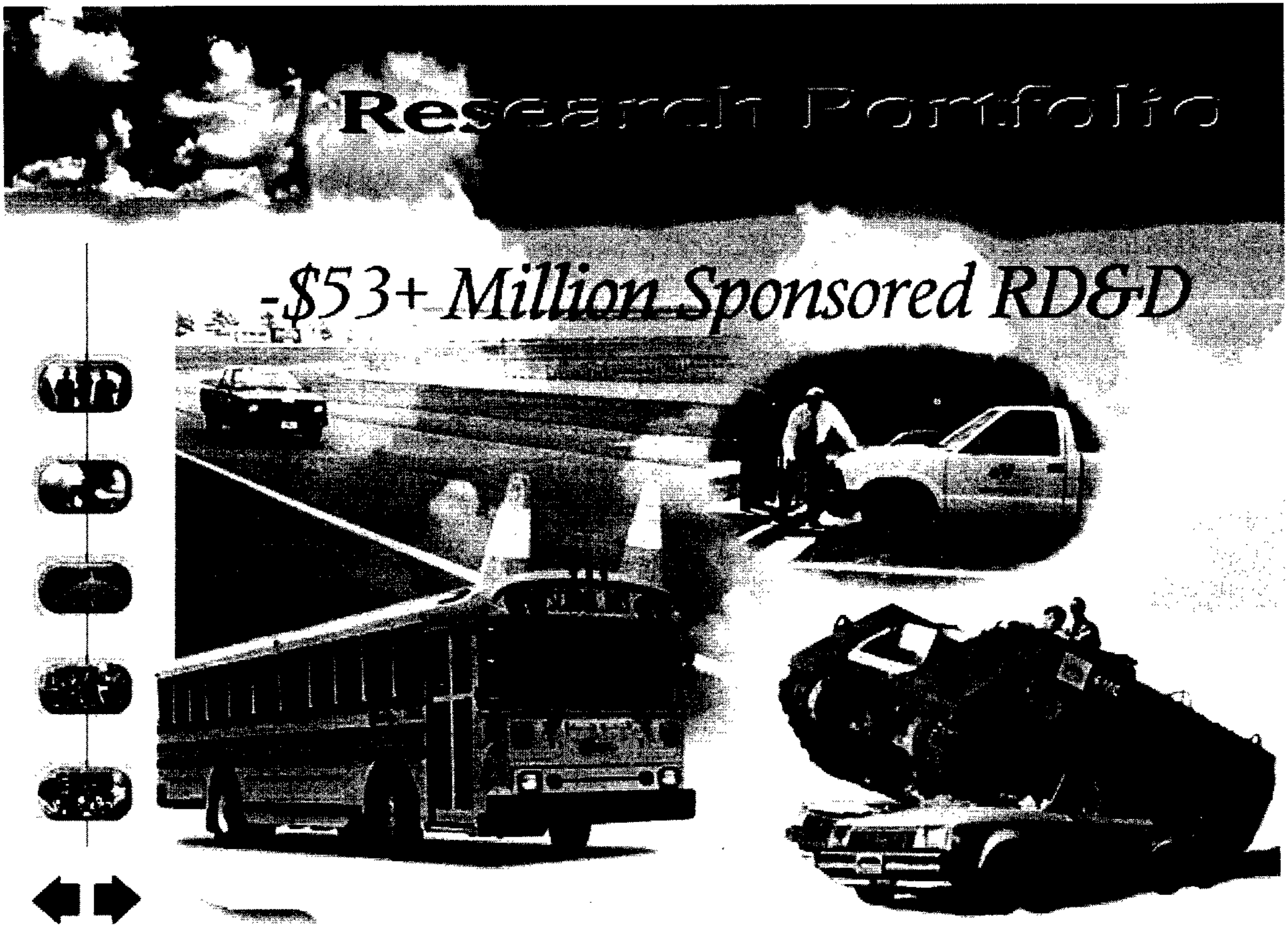
Members
Large Companies
Small Companies
Universities & National Laboratories
Utilities
Government & Transit Agencies
Military Bases & Test Centers


Research Portfolio
-$53+ Million Sponsored RD&D

Research Portfolio

- $53+ Million Sponsored RD&D
- Military Test Facilities
- GTRI Virtual Test Bed
- Chattanooga "Living Laboratory"
- Player in Clean Cities, CAVA & electroExpo
- Education Program in Development
- Olympic Effort
- Technologies Entering Market

Research Portfolio

-Research Projects

- Vehicular Flywheel Battery
- Electric Bus Battery Pack Development
- Commercially Viable Flywheel Battery System
- Rapid Charging and Battery Management
- Flywheel Integrated Mounting Skid & Vibration Testing
- DARPA Flywheel Safety Program
- Completion of an Electric/Hybrid Pickup
- Monitoring EVs in Florida Environment
- SCAT Support of the NDC
- EV/HEV Analysis Tool Using Simulink
- Back Bay Project
- Homopolar Traction Motor (HPTM) System
- Improved Cost and Performance EV Power Trains
- Electromechanical Suspension (EMS) System
- Variable Field Alternator (Fisher)
- Pulsed Motor Controller Technology Development
- APU for 22-Foot Bus
- Heavy Duty PM Traction Drive System
- Permanent Magnet APU for Heavy Duty Vehicles
- Advanced Locomotive Propulsion System
- 31-Foot Electric Bus Project Completion
- Hybrid-Electric HMMWV Development Program

Hybrid Electric HMMWV Development Program

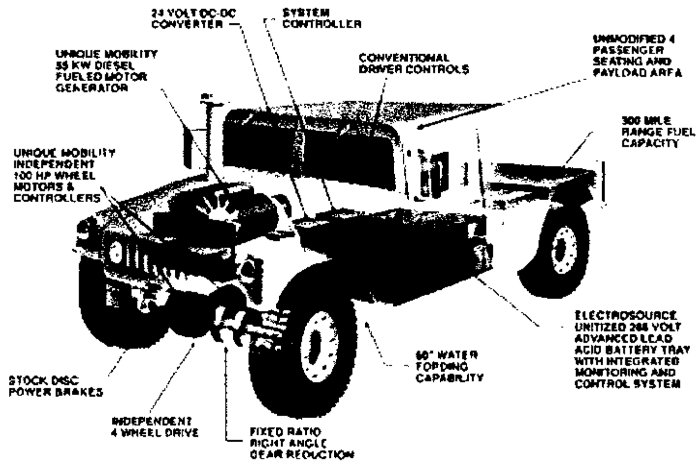
Participants

Electrosource

Unique Mobility

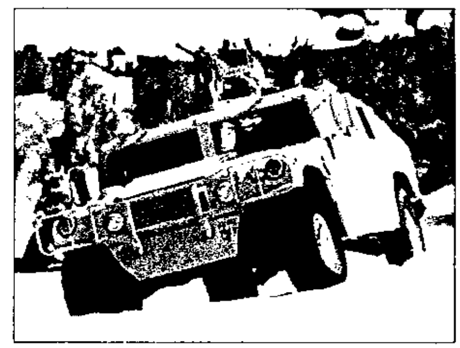
University of Alabama

Anniston Army Depot



Goals/Objectives:

Develop a prototype HMMWV which meets or exceeds all performance characteristics of a conventionally powered vehicle. Demonstrate a systems level approach to achieving program goals. Demonstrate a full featured vehicle concept using an integrated drive system suitable for both military and commercial applications.



Status:

- All mechanical modifications to the basic HMMWV are complete. The vehicle has been shipped to PEI for installation of vehicle wiring and electronic components.
- Road testing began Nov. 15; demonstrated at EVS-14; delivery to TACOM scheduled for 1st Quarter 1998.
- *Projected performance:*

Projected performance:	Units	Stock	Hybrid
Range:	miles	300	300
Top Speed on Grade:			
0%	mph	70	80
60%	mph	6.8	17
0-50 Acceleration:	seconds	14	7
Payload:	lbs.	2240	1700
GVW:	lbs.	9100	9100
Stored Energy:	kw-hrs	.72	24.5

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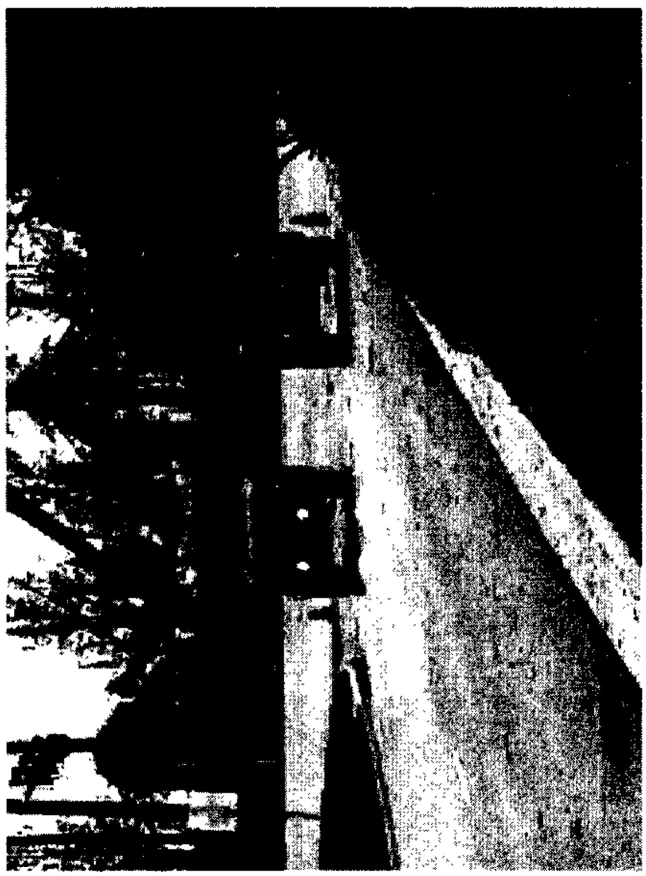
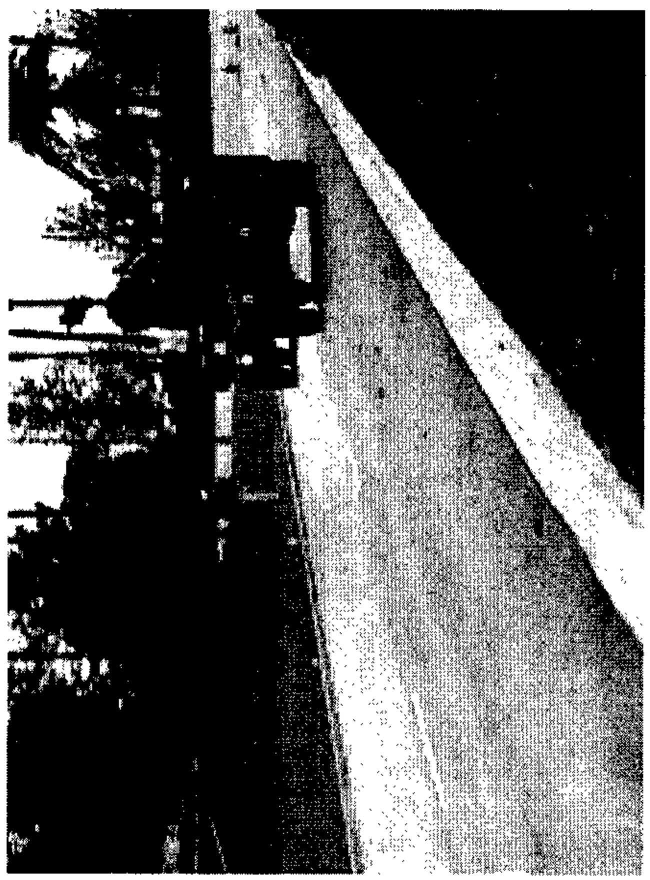


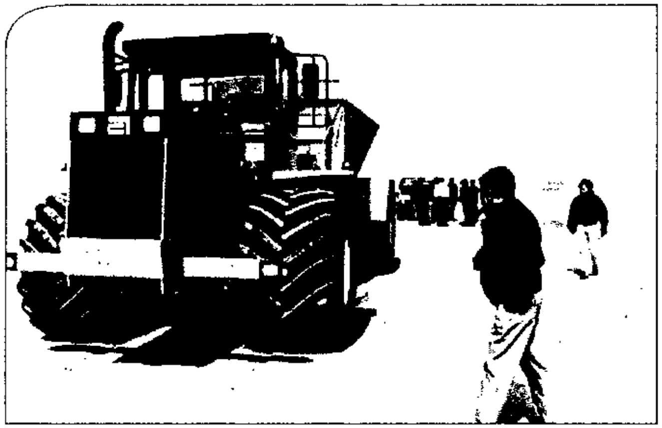



LIVE


LIVE

Back Bay Project

Participants



Goals/Objectives:

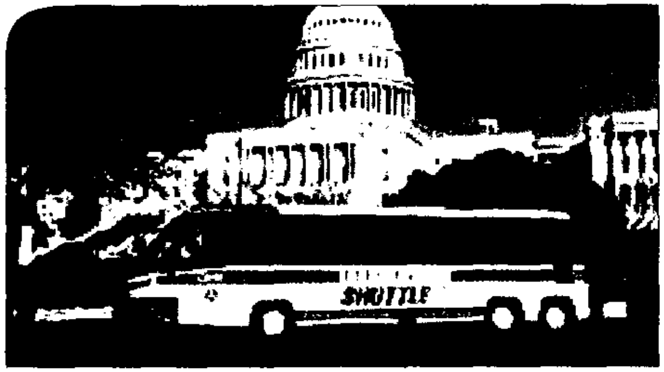
The purpose of this project is to design, acquire, and deliver a transportation system to move visitors to a combination federal wildlife refuge and state park located near Virginia Beach, Virginia. The transportation system, to be implemented over the next few quarters, will incorporate three all-electric trams capable of carrying up to 36 passengers each and a specialty-beach vehicle capable of transporting 40 students with backpacks and supplies for a weekend visit to the state's environmental education center at False Cape.

Status:

- The beach transportation vehicle has been identified and a purchase order for the chassis has been placed.
- All parts to complete the modification to the beach transportation vehicle have been identified, ordered, and received by MAPC.
- The electric trams and chargers have been delivered to Back Back, the electrical service upgrades are completed, and the dike improvements have been made to allow the trams to operate.
- The chassis was delivered to MAPC in November 1997. The modifications should be complete by the end of March.

31-foot Electric Bus Project Completion

Participants

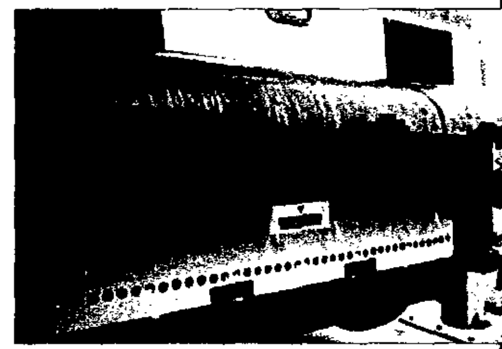


Goals/Objectives:

To design and manufacture an advanced 31-foot battery powered electric bus for operation in CARTA's electric shuttle system in Chattanooga, Tennessee. The project combines a proven Solectria 70 kW motor with SAFT Ni-Cad batteries on a 31-foot platform.

Status:

- SAFT completed construction of the battery pack, battery assembly, and watering system, including receptacles for each.
- Solectria completed construction of the drive system including two 70 kW liquid cooled motors, radiators, controllers, drive reduction unit, and drive system wiring harnesses.
- AVS completed all structural modifications to the 31-foot bus and installed and integrated the Solectria motors and SAFT batteries.
- The 31-foot bus operated under its own power on August 5th, 1997.
- NEETRAC will be installing a data acquisition system. ETVI and NEETRAC will design a series of reports that will provide useful information to both DARPA and CARTA.
- ETVI will be concluding baseline testing at the Electric Vehicle Test Facility in Chattanooga in April, 1998.



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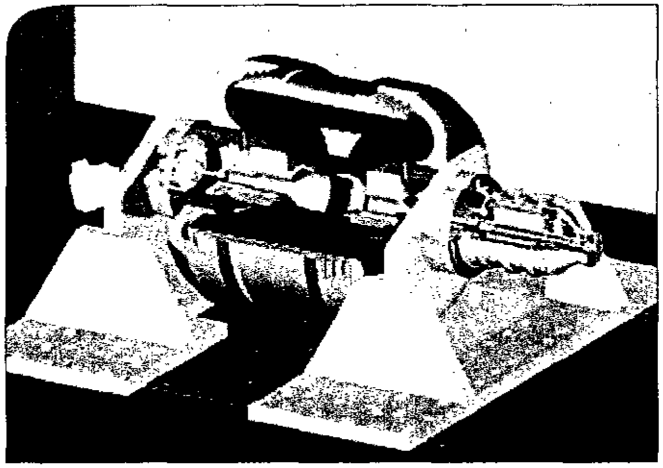
Advanced Locomotive Propulsion System

Participants

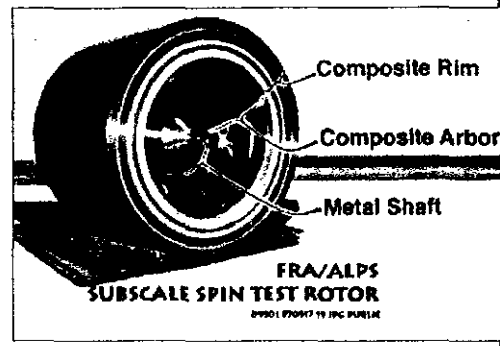


Goals/Objectives:

Demonstrate the feasibility of an advanced passenger rail fossil-fueled locomotive propulsion system with the following advantages:

- 150 mph operation on existing rail infrastructure
- acceleration comparable to that of an electric locomotive
- fuel efficient with low pollutant emissions
- avoid or defer $1,000,000 to $2,000,000 per mile rail infrastructure electrification costs

The ALPS concept employs a high power turboalternator to overcome rolling resistance and maintain cruising speed with a flywheel battery capable of delivering peak power for rapid acceleration, speed maintenance on grades, and recovery of braking energy.



Status:

Construction of full-scale flywheel battery components ready to proceed

All major component stock material forgings, castings, composites, etc. have been purchased and received

- Final machining/fabrication of full-scale hardware on hold until *subscale development tests are complete*

Extensive sub-scale testing is validating salient features of full-scale design

- Ferrofluidic shaft seal performance tested and validated
- Extensive composite material property characterization has been performed
- *Trial-windings of subscale composite arbors* are complete
- Spin-testing of two subscale composite rotor assemblies has been completed
- Construction of a sub-scale containment enclosure has been completed
- Burst-test attempt of one sub-scale rotor in a subscale flywheel containment-enclosure was performed on 10 Oct. 97

Development of 2.5+ MW motor-generator underway

- Preliminary design review completed
- A rolling demonstration of ALPS turbine/flywheel technology in a prototype commercial high speed rail locomotive is planned for CY 2000
- Competitive selection of vendor for development of *Rolling Demonstration locomotive platform* to be held early CY 1998

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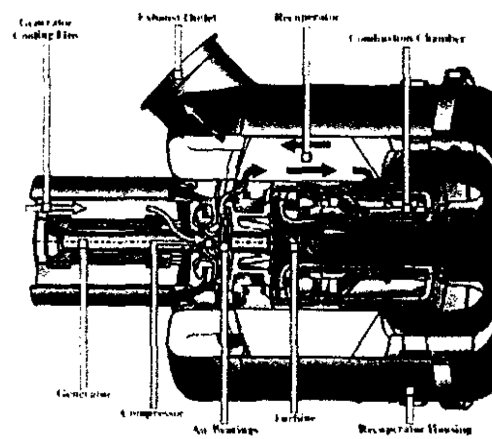
APU for 22 Foot Bus

Participants

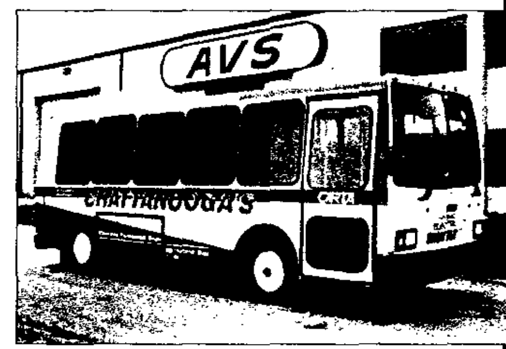
The Capstone Turbogenerator



Capstone Turbine Corporation

Goals/Objectives:

Identify, integrate and test range extending auxiliary power unit in a 22-foot bus previously manufactured by Advanced Vehicle Systems, Inc. and currently in operation by the Chattanooga Area Regional Transportation Authority.



Status:

- AVS established the operational requirements for the APU and selected the compressed natural gas fueled Capstone Turbine APU from Capstone Turbine Corporation, developed through a DARPA/CALSTART project.
- AVS and Capstone integrated the APU into a 22-foot CARTA bus. This included testing and evaluation and in-house modification and correction.
- CARTA began operating the 22-foot hybrid-electric bus in its electric shuttle service in late July, 1997. Data received by AVS is being transmitted to DARPA.
- The bus was available for rides during EVS-14.
- Data from the operation of the bus will continue to be transmitted to DARPA.

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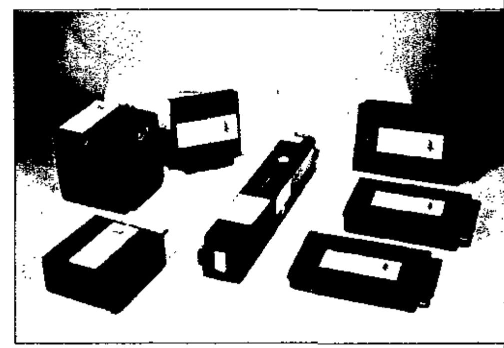
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION

Electric Bus Battery Pack Development

Participants

Goals/Objectives:

- Develop a high-capacity battery for heavy-duty EV use.
- Develop a charge management system (CMS) for heavy-duty battery packs.
- Install batteries and CMS in a Blue Bird school bus.
- Demonstrate improved performance in the school bus.



Status:

- High capacity battery has been developed and is in the final proof of concept testing.
- Charge management system (CMS) is developed and ready for installation.
- Battery vibration testing is planned for the end of February at Blue Bird.
- Cycle life testing is continuing on prototype battery.

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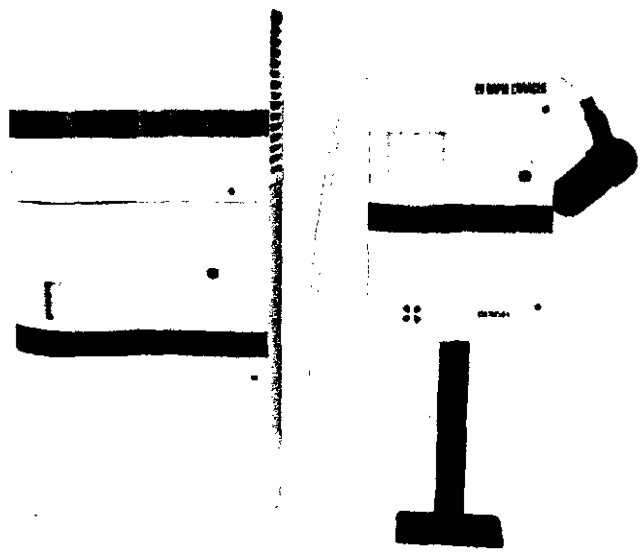
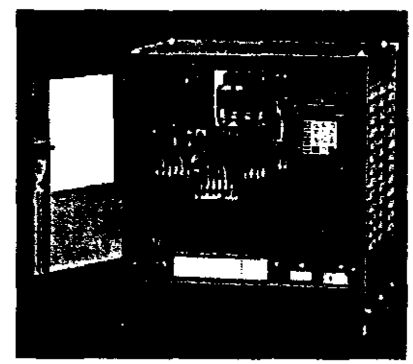
Rapid Charging and Battery Management

Participants



Goals/Objectives:

Design, build, and deliver two different high power chargers for heavy duty electric vehicles. Install battery management systems on a Blue Bird and an AVS Electric Bus and integrate them with high power chargers using SAE J-2293, Energy Transfer System for Electric Vehicles.



Status:

- Consortium Agreement under review by Team.
- Initial design work underway at Schott Power Systems and Ferro Magnetics Corporation.
- Vendors under review to supply the Battery Management Systems.
- Vendors under review to supply the new battery pack for the Blue Bird Bus.
- Select and procure the Battery Management Systems for both buses - *planned.*
- Select and procure the batteries for the Blue Bird Bus - *planned.*

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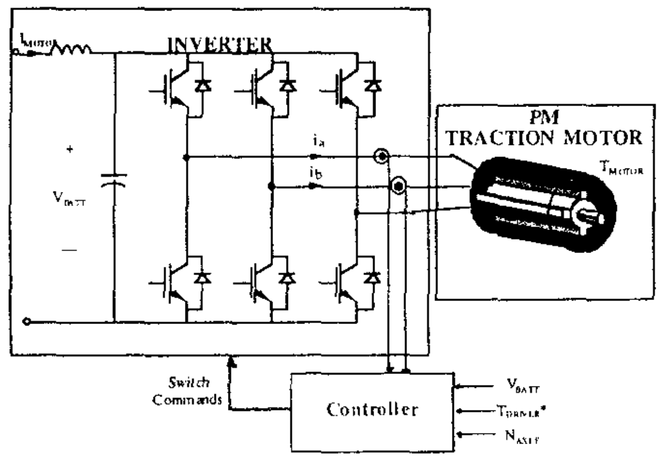
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION

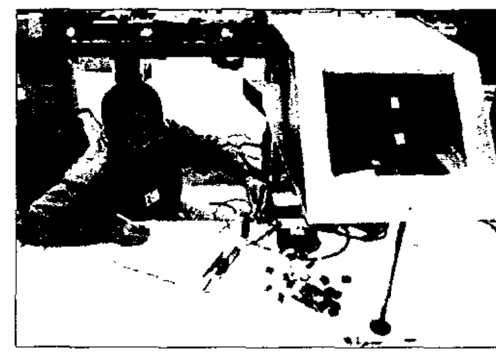
EV/HEV Analysis Tool Using Simulink

Participants



Goals/Objectives:

The project goal is to develop models and program code for the major electrical components in the "PATHS" toolbox. PATHS is a software tool for assessing and predicting the *performance of HEVs. It provides users with a* common tool capable of simulating a variety of drive train options, new vehicle designs, control laws, and driving cycles. The SIMULINK modules contain equation-based models, with user-specified parameters. This type of simulation is particularly suited to vehicles which are still to be detail-designed and/or built.



Status:

The following models were developed, tested, and released during the reporting period:

- Steady-State *Induction Machine - Traction Motor System with* Calculated Inverter Losses
- *Steady-State Permanent Magnet Generator* System Module with Calculated Inverter Losses
- Steady-State Permanent Traction Motor System Module

Steady-State Wound Field Synchronous Generator System Module with Fixed Efficiency and Field Current Supplied by the DC Bus.

The Nickel Metal Hydride Battery Model is being done in C code and the final report will be submitted next quarter.

The system will be converted to MATLAB 5/Simulink 2.0 and all existing models will be converted to all per-unit calculations next quarter.

Validated Code on HVAC modeling

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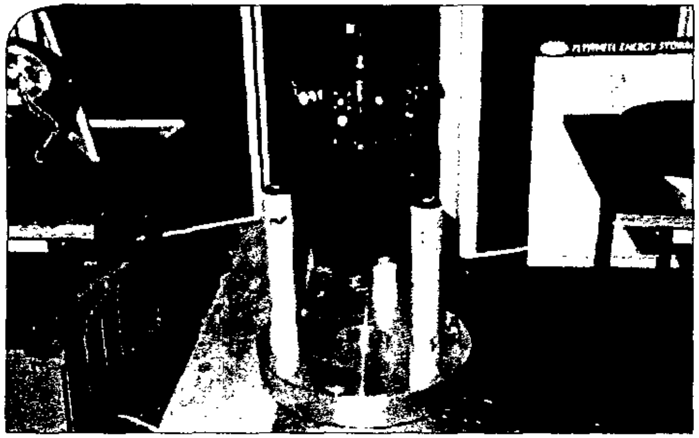
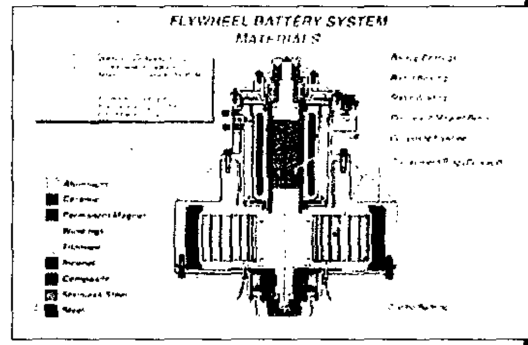
Vehicular Flywheel Battery

Participants



Goals/Objectives:

The purpose of this project is to develop a flywheel battery suitable for installation on a public transit bus. The system will incorporate a composite flywheel developed by UT-CEM; magnetic bearings designed by Avcon; and a high speed permanent magnet motor generator built by AlliedSignal. The flywheel battery is designed to provide a robust, reliable, high power density, load leveling device operating between 30,000 and 40,000 RPM with a peak power output of 150 kW and an energy storage capacity of 2 kWhr.



Status:

- System design completed and technical hurdles identified; magnetic bearing operating speed limits increased, creep resistant composite materials identified, fatigue resistance of composite materials verified, motor/generator losses identified as critical issue.
- Component fabrication completed; magnetic bearings, backups and dampers delivered to CEM, motor generator rotor and stator assembled , all rotor components assembled, final machined and balanced.
- Component testing nearing completion; magnetic bearings load tested and operated at 5,000 RPM, backup bearing dampers vacuum tested, motor/generator seals tested under pressure and vacuum, motor/generator magnet strength verified, composite flywheel spin testing confirmed modeling.
- Critical issues being addressed on parallel programs; fuel savings and cost advantages- Houston Metro simulations, safe operation of flywheels- DARPA Containment Projects, commercial viability of flywheel batteries- DARPA Commercial Viability Project Cost shared by EPRI and Texas Utilities, mechanical integration - Combined Houston Metro and DARPA integration and vibration testing projects.

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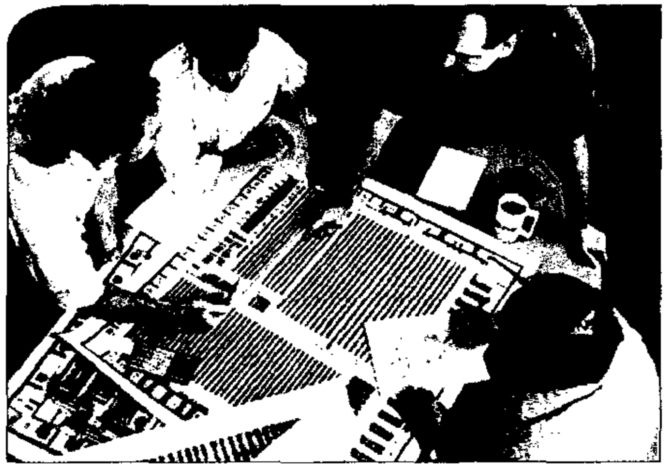
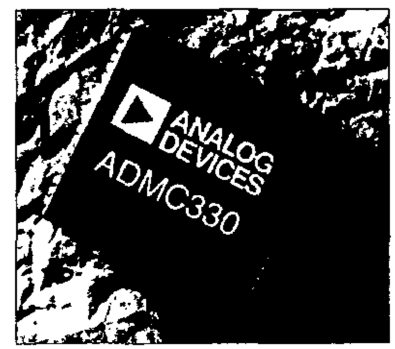
Improved Cost and Performance EV Power Trains

Participants



Goals/Objectives:

Develop a low cost inverter for electric vehicle applications. Hardware reduction acheived through the design of a single DSP-based Motor Control chip and the design of smart power modules. Power Converter Topology and Modulation Algorithm Development used to improve torque control and reduce inverter capacitor bank and heat sink size.



Status:

- ADI has provided working samples of the ADMC300 DSP microcontroller, debugging tools and documentation for evaluation.
- GE has moved the induction motor control software from the control hardware that simulated the ADMC300 to the actual ADMC300 platform.
- VPEC has completed efficiency measurements between the new RA94-based inverter using control hardware that simulates the ADMC300 and the old EV inverter design.
- Complete the inverter testing with the new ADMC300 on the dynamometer - *planned.*
- Install the inverter in a test vehicle and test .
- Program Complete - *Final Report Submitted January 98.*

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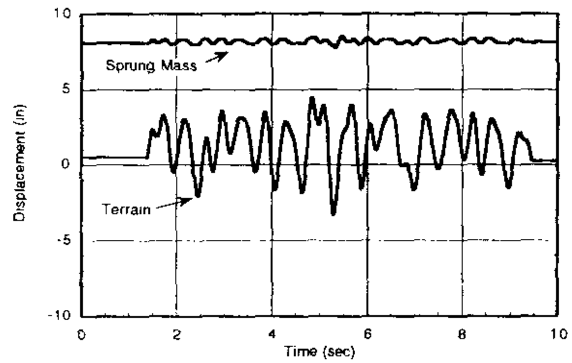
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION

Electromechanical Suspension (EMS) System

Participants



Status:

Feasibility demonstration (completed 1995 - TARDEC, NAC)
- Proof of concept
- Single wheel test rig

Critical Technology Development I (Completed 1996 - DARPA, Texas)
- Multi-wheel algorithms
- Four-corner test rig

Critical Technology Development II (Completed 1997 - DARPA, TARDEC, NAC)
- EMS linear actuator development
- Durability testing

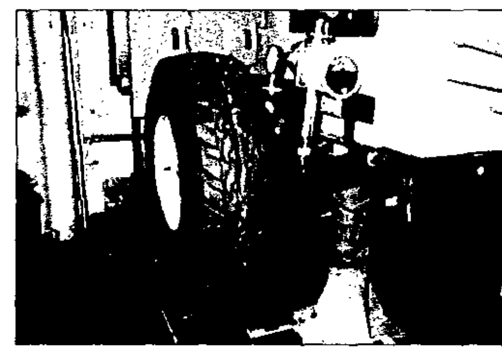
Technology Demonstration (DARPA, TARDEC, NAC, Houston Metro) - *planned*
- Integration on HMMWV and on transit bus
- Field tests
- Anticipate October Starts

Transit bus demonstration work initiated in November 1997.

Begin HMMWV program in March 1998.

Goals/Objectives:

The University of Texas Center for Electromechanics is developing active suspension technology for off-road and on-road vehicles. The heart of the system is the UT-CEM advanced control algorithm. The primary hardware component of this suspension is a linear fast-acting electromechanical actuator that minimizes vehicle vertical motion by maintaining a constant force on the sprung mass (body) as road terrain creates vertical displacement in the unsprung mass (wheel) and controls vehicle roll during turns.



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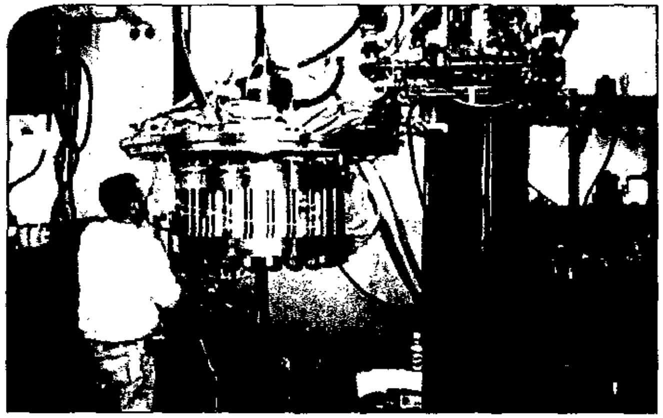
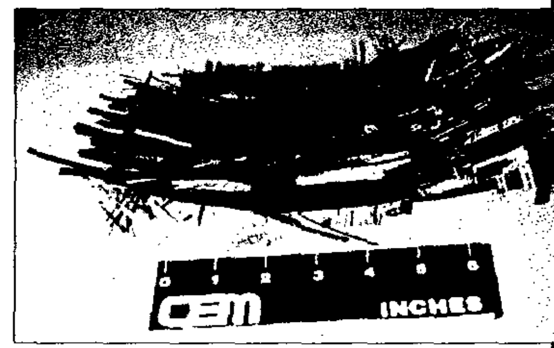
DARPA Flywheel Safety Program

Participants



Goals/Objectives:

To address the containment issue, DARPA has funded a Flywheel Safety Program to both determine the effects *of typical composite* flywheel failures and develop systems to mitigate those failures. The objectives of this project are to develop burst test technology; conduct a combined *theoretical and experimental program to gain* a fundamental phenomenological understanding of composite flywheel failures; and devise a basic methodology for design of containment structures and systems. The program is fully integrated with *Department of Energy efforts in composite* flywheel containment and emphasizes technology sharing within the U.S. flywheel battery community.



Status:

- 48" diameter composite *flywheel spin test cell installed* and used for program testing
- High speed digital video camera and laser illumination system purchased under this program and available for use
- Light gas gun test data evaluated for relevance to candidate containment designs, also conducting new light gas gun tests
- Developed analytical models to predict loads resulting from flywheel bursts
- Seventeen flywheel tests have been conducted to date
    - Overspeed flywheels to failure to verify maximum operating speed and identify *failure modes*
    - Capture of flywheel burst on high speed video
    - Burst flywheels in instrumented containment fixtures to measure burst loads
    - Failed flywheels in candidate containment designs
    - Calibration of analytical models
- Validate analytical models with test data and proof test candidate containment designs for several different flywheel designs - *planned*
- Develop general containment design guidelines - *planned*

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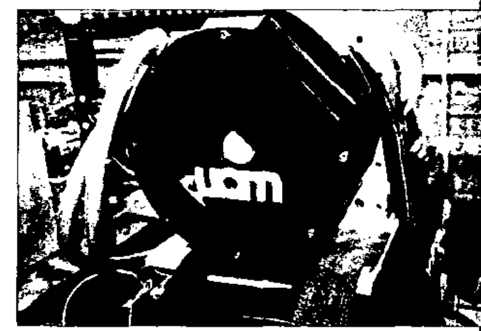
Heavy Duty PM Traction Drive System

Participants

Goals/Objectives:

The project focuses on the development of a traction motor designed specifically for mounting directly on the suspension at the wheel and driving the wheel through a fixed reduction gear ratio. The system hardware is complete and dynamometer testing for system performance evaluation, software improvement and documentation is in process at Unique's facilities in Golden, Colorado.



Status:

Traction Motor Development
- Detailed Performance Specification, Phase Advance Analysis, Electromagnetic Design Motor Mechanical Design, Motor Documentation and Dynamometer Design is complete

Power Electronics and Microprocessor
- System Specification is complete
- Continuous Power Electronics Evaluation is 90% complete, final documentation remains
- System Communication is 60% complete, dynamometer testing and documentation remain
- Drive Interface Improvements is 95% complete, final documentation remains
- Software Support is 20% complete, power and performance evaluation remain
- Power Electronics and Microprocessor Build are 90% complete, final button up and modifications remain
- Final Documentation Support is 50% complete, remaining to be complete following dynamometer testing

System Evaluation and Testing
- Initial System Testing is 20% complete
- System Modification defined by Initial Testing are in process
- Final System Test and Report are in process

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Permanent Magnet APU for Heavy Duty Vehicles

Participants

Status:

Notification of the program award has recently been received and the program is in the "kick-off" stage. With the recent announcement of the program considerable interest has been shown by a number of large vehicle manufacturers and users.

At this early time the program has not experienced any problems and work is expected to continue on the original schedule and scope.

The tasks that are planned for the next review period include:

- **Definition of system and Component Specifications;**
  Prior to starting the physical design and construction of the proposed APU, significant effort must be directed to investigating the various applications for the APU and defining a clear set of specifications that fulfill the application requirements.

- **Detailed Design;**
  Based on the specifications defined above, the detailed design effort will start. The outcome of this effort will be detailed designs that will be used to fabricate components and construct the APU.

Goals/Objectives:

The primary objective of the program is to develop a fully integrated, commercially available auxiliary power unit (APU) for larger electric vehicles where the range-extending ability of a hybrid is desirable. Typical vehicles that will benefit from the proposed hybrid APU system include: School and Medium/Light Duty Transit Buses, Military Vehicles, Agricultural and Off-Road Equipment. A second goal is that the APU is to be developed as an integrated system that is a single package and can be applied to various vehicles using different electric drive system technologies.

Unique Mobility, Inc

SCAT
SOUTHERN COALITION FOR ADVANCED TRANSPORTATION

Achievements

-Chattanooga

- Population: 152,466 City; 433,210 Metro area
- Rejuvenate downtown area
- Free shuttle system for electric buses
- Outreach: Costa Rica, Denver Summit
- Active community: CARTA - Strive for all-electric fleet
  ETVI - Promote electric transportation,
  Managed all-electric Olympic system
  Advanced Vehicle Systems- 60+ buses sold
- Over 3.1 Million trips in 5 years of service (4/92- 4/97)

1992	525,762	1995	712,619
1993	500,678	1996	734,164
1994	515,736	1997(qtr1)	147,857

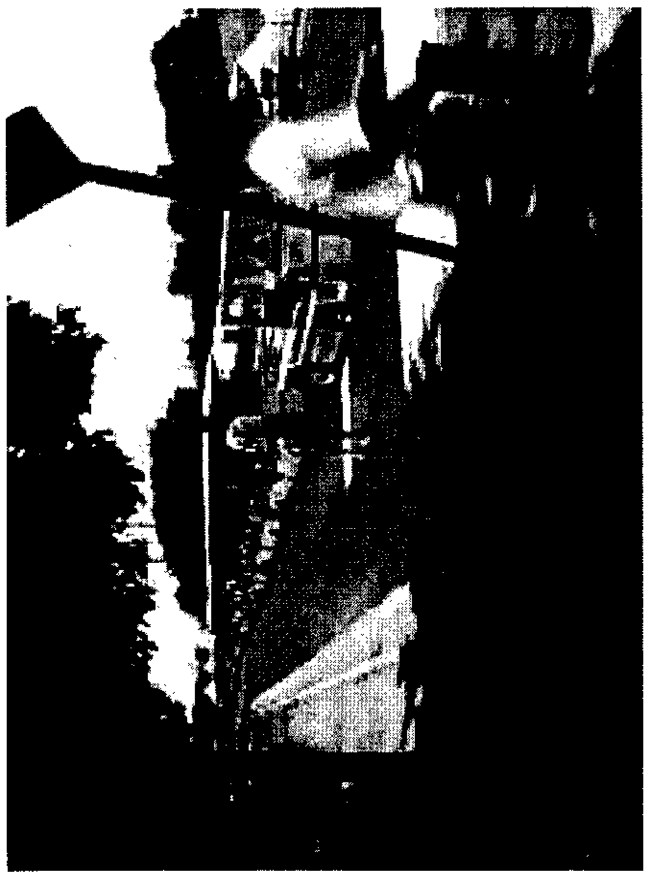

Achievements
-Chattanooga
SHUTTLE PARK SOUTH

Achievements

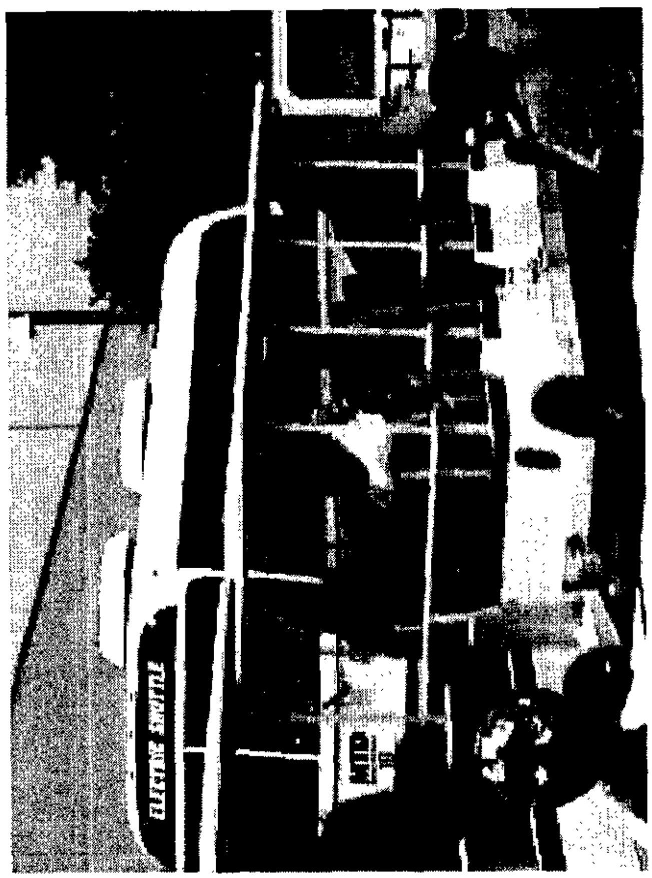
-Chattanooga


Achievements
-Olympics


Achievements
-Olympics




ELECTRIC SHUTTLE
MTD
10



DOMESTIC COMPETITIVE PRESSURES FOR CLEAN COAL TECHNOLOGY

Bruce A. Craig
Director, Utility Regulation and Environmental Affairs
Natural Gas Supply Association
Washington, DC, USA

Good afternoon, hope you guys can bear with me through the beginning of the lunch period because I'm going to keep you here for the next two hours. Actually, I'm going to try to keep things short and get us back on schedule. In doing so, I'm going to try to focus on a couple of particular areas, mainly in the electricity restructuring area.

Some things that have posed very significant threats to CCT development and also to the capital infusion you guys so desperately need to advance the level of technology you have. In general, environmental pressures, distributed power generation, and development of high efficiency technologies are the three fundamental domestic threats to the ability for CCTs, and, by extension, the ability of coal-based generation to continue to dominate power markets over the medium and the long-term.

Clean burning natural gas is the most obvious threat today. However, to focus solely on the gas-based threat I believe to be shortsighted and really ignores the looming changes in the technology and policy that may soon challenge us both significantly. As members of the fossil producing community we share a lot in common in terms of the threats to our existing market and to our new potential markets. Policy makers and pundits from all sides of the equation have overblown the coal versus gas controversy and the confrontation in competition for new markets. I think that each fuel and the technologies that back each fuel up, if they're allowed to, are likely to remain a significant and healthy electric market participant into the future. Frankly, I think it is necessary for the Nation's economy. Competition in wholesale and retail markets nationwide will further challenge us in defining new roles and applications for fuel and technology and combinations. These combinations will compete head to head for new generation markets. The growth in electricity demand will define what is available for us to compete for. I am talking about new merchant plants, new IPPS, repowering, and all of the power generation target markets that CCTs and gas are likely to compete for.

In a fully competitive generation market, which many of us envision (and frankly we in the gas industry are hoping for), the plant designs and the financing choices are going to be made based on economics, operational characteristics, and environmental performance. It is vitally important that an open market for new generation develop. Transparent market signals are critical to achieving the most efficient allocation of capital for infrastructure investment and R&D.

As you have heard throughout the conference, gas-fired combined cycle plants are attractive candidates for new generation capacity. Consequently, gas-fired plants are predicted to garner a large share of the investment in new generation over the coming decade and further into the future. The realization of this prediction is made possible by the research and development efforts and the capital investments that the gas industry, manufacturers, and the power generation companies have made over the past several decades. And frankly, it hasn't been done without the support of the DOE. I wanted to acknowledge some of their programs. The performance and efficiency of gas exploration production transportation have improved significantly in the past two decades. New exploration production technologies have more than tripled the success rate of drilling for new reserves. It has completely revolutionized the way we, as producers, approach the commodity market and the resource base itself. These technology improvements have enabled producers to replace reserves in a greater than 100 percent of production for the past ten years.

Similarly, the turbine manufacturers have improved thermal efficiencies from the mid-20 percentile range above 55 and approaching 60 percent with the new combined cycle technologies. These advances would not have developed as rapidly or as successfully <u>without ending the federal intervention</u> that existed in the '70s and early '80s, over competitive portions of our industry. Both gas and electric.

From the gas side, I'd like to talk about some of the experience that we have had. Ending federal well-head price controls and production controls that existed primarily out of the Carter-era energy control, federal forcing of markets, provided clear price signals to the marketplace and improved the supply and demand balance of natural gas. It has helped us build our infrastructure to connect markets with the production areas on a much more rational basis than it was done before. It also rationalized, through market transparency, the allocation of at-risk capital for investment in production technology and gas reserve development. Consequently, the production response to increased demand has improved significantly. Supply has increased dramatically. We are up above 23 trillion cubic feet this year. We have just passed our previous high, which preceded the Carter era days back in the early 1970s.

Over the period of that dramatic increase in demand for natural gas, supply has kept pace while prices have declined in real terms. The implementation of the technology advances that made this possible accelerated directly in response to the market forces that were unleashed by ending the federal control over those markets. Opening power markets wholesale access of FERC really began the process of introducing competition for generating electricity. It was the first chink in the armor of the monopoly utility franchises' grip on power production.

Frankly, it is just on the margin. But, a lot of the improvements you have seen in combined cycle technology and the deployment of that in much wider areas really came from small changes in the federal policy that allowed competition for incremental growth and generation. And now, state restructuring and the threat of federal restructuring have initiated a swell of interest in at- risk plants and other generation projects, such as the Trigen ventures that were discussed earlier.

These are real important parallels between the expected ascendance of gas-fired and commercial challenges for CCTs and their deployment. It is essential to providing market incentives for investments in new technologies. Amongst other drivers, such as clean air act regulations, direct market forces are the most important factor in unleashing the necessary capital for research and commercialization of these technologies. Electricity restructuring itself has the potential to ensure robust future for all fossil fuels. Conversely, the restructuring at the federal level actually could present some of the biggest barriers to fossil fuel use in generating power and may result in lower fossil fuel demand in the future. Both gas and coal.

The mechanics and timing of the federal restructuring of the industry that are going to have a profound effect on markets well beyond that of electricity. The impact on technology deployment and on natural gas and coal producers will include changes in demand patterns, market structure, prices and load profiles, all requiring requisite response by all of us in that "designed" commercial environment.

It is vitally important to ensure that the legislative and regulatory changes affecting the structure of the electricity industry provide the opportunity for all competitive market participants to respond on fair terms. I'd like to touch briefly on two areas. Some of you know Washington well enough to know that we have been working very hard to neuter some efforts to dictate market outcomes which we believe will have very devastating effects on the ability of fossil fuel generators, gas, coal, and new technology deployment in the growth markets for electricity generation.

The first one is nondiscriminatory open access. As you've heard earlier, there are a lot of barriers that are being erected to open access, in terms of customers having access to the independent power production, and the ability to self generate. These barriers are being set up by incumbent monopolies–exit fees, stranded cost allotments, back up power, distribution pricing schemes, and transmission pricing schemes. They come in a lot of different forms. And those of you in the utility industry probably know them better than I do, because of their working very well to block new generators from entering markets. We perceive these developments as being very negative element to the market structure in terms of being able to deploy new technologies like CCTs and gas that should have a robust future.

The second and most important issue is renewable energy mandates that have been proposed by this administration, as well as by several congressmen and senators. Those range from a low of five percent to a high of 20 percent of total electricity generation in the United States. That's an amazing figure if you look at that--20 percent of total electricity generation. We didn't even run numbers that high on our scenarios because we perceive that to be so ridiculous to be unattainable. These mandates are for non-hydro renewable energy sources. Concurrent with our analysis, the Energy Information Agency, the Environmental Protection Agency, and the DOE, as well as several other industry studies confirm our conclusions that any significant mandate for renewable energy generation would essentially displace a very significant amount of coal and natural gas-fired generation, both in the existing fleet of plants as well as in competition from new markets. Because, when you're mandated it doesn't make any difference what your cost base is. So, essentially you are not competing with those of us who are looking strictly at a bottom line application to compete for retail and wholesale electricity markets.

Mandates directly conflict with the objective of restructuring, number one, which is philosophically and commercially abhorrant to those of us who believe in and require free markets. It also violates the premise of what we are here for today; to try to figure out a way to assess and eliminate the barriers that we face. I'm looking at it from a gas perspective. You all are here to assess it from a CCT perspective. What we want to ensure from federal policies is that we have a competitive market that allows the technologies to compete on their merits that also spurs investment and commitments to new technologies, including the CCTs. Frankly, we are gravely concerned about the economic consequences of replicating these types of past national policies that dictated these market outcomes. Frankly, the natural gas industry is probably one of the best suited to be able to tell you about the adverse impacts of market command policies of the Federal Government. Some of the problems have been fixed but unfortunately it appears that they are going to try to go and pursue some new market control initiatives.

To conclude, Bob was right, natural gas is probably the most legitimate, strongest and current competitor against clean coal technology. I believe that given the proper incentives, capital is going to flow to more targeted investments that will make you a much more fierce competitor in the future against natural gas-fired generation projects. However, the single largest threat to both of our industries right now may be the policy and legislative efforts to dictate generation market outcomes. Renewable mandates are reminiscent of the Carter area market controls, and we as consumers and producers are painfully aware of their negative market impacts and the effect on the ability to facilitate progress and innovation. I would urge you to get involved to stop the development of policies that would actually manipulate the markets in these ways. Frankly, that's the only way we can guarantee that there is a market for us to compete against each other in.

Thank you.

LUNCHEON

Domestic Marketing Challenges

Thank you, Secretary Rudins, and thank you ladies and gentlemen.

Commendations to all for this Sixth Conference on Clean Coal Technology. The program is comprehensive and the presentations of the highest order in detail and in quality.

Public commendation is due as well to the developers of applications that are the subject of these presentations. They shall raise America's power-generation potential to higher levels of efficiency, environmental effectiveness, and economic vigor.

Your work will prove to the present and oncoming generations of Americans the truth behind the saying:

> Science can fascinate but it's engineering that changes the world for the better.

I was asked to discuss domestic marketing challenges.

Asteroids and English literature may be the best introduction for the greatest challenges.

Think back to your school days. Remember that the text of many old English plays came with written stage directions in the dialogue.

The stage direction "alarums and excursions" is common in Shakespeare's work.

"Alarums and excursions" were devices to move a drama forward by moving the emotions of the audience -- explosions or heart-stopping noises or shouts from threats often unseen. They invited clamor, excitement, and fevered disorder to override judgment.

The technique is not without application in contemporary public affairs.

Modern spelling still puts the letter "u" in the last syllable of alarum to set it apart from a true warning -- to show it a device of art.

The Asteroid Scare of 1998 goes to the essence of "alarums" in policy. It gave doomsday an hour and date -- Thursday, October 26, 2028, at 1:30 in the afternoon. It soon dominated the nation's television news and most conversation.

Then a recalculation proved there had been a mistake. The value as an example is that this excursion concentrated into one day a pattern that can otherwise take years to play out -- play out as follows:

> •The end of life-as-we-know-it is postulated for a time just over the horizon -- too close to ignore, but so distant that most now living won't be around to see if it comes true;
>
> •Doomsday is broadcast and published widely -- it saturates society;
>
> •The build-up of opinion demands instant identity of the causes, indictment of the doubters, and immediate protection;
>
> •Pressures rise to invoke public policy;
>
> •Remedies are proposed;
>
> •Recalculations are made;
>
> •The horizon for doomsday moves back;
>
> •And the end of life is postponed even before the remedies can take hold.

Some alarums are like the Asteroid of 1998, and fade without harm; but others are only half so.

I urge you, recollect the alar alarum.

The professional green lobby induced television's most-watched program to advance in the guise of news the proposition that the apple industry was willfully exposing children to long-term health risks to protect profit.

The proposition was disproved in a few days; but not before it shook the apple industry -- if you will excuse this -- to the core: literally almost brought it down.

This was the case with nuclear winter.

Nuclear winter produced great anxiety and even greater political and politicized discussion; but no change in policy. It fell slowly to proof.

This was the case with acid rain.

Acid rain produced much discussion of both kinds; and a change in policy; and an after-the-fact recognition that there had been no crisis.

And this may well become the case with the climate postulation. The first prophesies of dire consequences are being continually and substantially eroded by fact and study.

Not long ago a leading climate scientist wrote in a scientific journal that, in essence:

> •An emergency program of deep government intervention and stringent energy control might well stabilize carbon concentrations as early as 2150;
>
> •But a line of action that simply lets technology advance means stabilization will have to wait until at least 2150.

You did not misunderstand. The scientist found a droll way of saying his models tell him punitive controls will make no difference to carbon dioxide -- the controls most passionately advocated will make no difference.

The greatest domestic challenges are social and political, not economic and technical.

Against this background I invite you to join me in thinking about how these technologies of ours can be helped to change the world for the better.

We'll have to think about other changes as well -- interacting changes:

- •The forces that drive social opinion and, thereby, politics;
- •And changes in the electric power industry.

We'll have to think in the short-term, the mid-term, and over the horizon -- that is, beyond 2020.

Like the electric power industry, we have some unbundling to do.

The best point of beginning may be electric power.

To proceed otherwise would be akin to putting the Pinon Pine heat-recovery steam generator at the air intake of the combustion turbine -- it could be easier, but it won't work very well.

I promise, however, to tie the bundles back together and, then, to arrange them into a line of thought.

The only foreseeable ways to generate large volumes of electric power reliably and economically are:

- •Steam raised in nuclear reactors;
- •Hydrogeneration, which requires big dams and falling water;
- •And the combustion of fossil fuels for steam, or in combustion turbines.

The early forecasts that used the present for their far horizon saw an expanding role for nuclear generation in the American power mix.

The new *Annual Outlook* of the Department of Energy sees the following:

- Early closing of plants with output too expensive for a competitive market;
- No replacement;
- And probable decline in output of 50 percent to the horizon of 2020.

U.S. nuclear power was stunted by factors that include:

- Alarums;
- Some missteps;
- Big events outside the U.S.;
- And the inability to close with some underlying social and political challenges.

There was an onslaught -- legal campaigns, regulatory campaigns, and public opinion campaigns. They complemented and built on one another.

There were fights at every move: Fights to permit plants; fights while they were in construction; fights to put them on line; and fights to keep them in operation.

The campaigners had objectives, often unrelated to specific outcome, in everything they did -- to raise social concerns, to foster uncertainty, and to induce political involvement.

The tactics are being turned against hydro-power in the Pacific Northwest, and selected other dams. Expansion potential is limited.

The *Outlook* sees hydroelectric output holding steady. Experience says the campaigns will intensify -- and instinct that there will be some loss to politics or to periodic low water.

My point: Two of America's three reliable and economic sources of power have been put out of bounds by social and political challenges.

Public consent for their expansion was revoked.

What will Americans require through 2020?

Electric power is the one not-to-be-dispensed-with ingredient in a modern economy -- its abundance a condition of growth, its lack a predicate for decline.

Americans will demand a strong modern economy -- one that can win and hold a foremost place in the global economy.

Thus America will require more, not less, power; and power at lower, not higher, costs.

The *Outlook* sees growth from 1995 as follows:

- By 21 percent through 2005;
- By 30 percent through 2010;
- By 45 percent through 2020;
- And cumulative growth of 1,300 billion kilowatt-hours.

Now let's factor in the declines. For discussion let's factor as follows:

- 350 billion hours to offset the 50 percent nuclear decline;
- And another 50 billion for hydro;
- For a make-up increment of 400 billion kilowatt-hours.

The new requirement: 1,700 billion kilowatt-hours.

To compare: This 1.7 trillion kilowatt-hours equates:

•To 55 percent of our requirement last year;

•To more than the combined requirement of our primary global competition -- Japan and Germany;

•And to more than Europe's dominant economies combined -- Germany, France, Italy, and the United Kingdom.

The *Outlook* estimates the next 22 years will require the following steps:

•Repower and refurbish 232,000 Megawatts;

•And build new capacity of 403,000 Megawatts;

•For an increment of 635,000 Megawatts.

At the same time there will be fundamental and transforming change in the price-regulated electric power industry.

All new power will be produced under the National Energy Policy Act of 1992, which was enacted in consequence of the Persian Gulf War to uphold America's energy and economic security.

The act requires producers and sellers to compete. Small and protected local markets will be replaced by competitive forces acting in regional and national markets.

No more will the efficient and inefficient be blended in one fixed rate. No more will profit be guaranteed and all customers captive.

Soon companies will have to compete and customers to choose based price -- price and any other other consideration they choose.

Here are some system costs from California:

•Coal -- 2.8 cents a kilowatt-hour;

•Gas -- 5 cents, or 79 percent more;

•Wind -- 11.6 cents, or 324 percent more;

•Geothermal -- 11.9 cents, or 325 percent more;

•And, finally, solar -- 15.4 cents, and 454 percent higher.

These are real costs -- the competitive market's equivalent to a regulatory certificate of convenience and necessity.

The Utility Data Institute has ranked the best U.S. power plants by costs that include fuel.

The ranking condensed as follows:

•Lowest cost -- coal at 8/10ths of a cent per kilowatt-hour;

•And the 12 best are coal;

•And 82 of the best 100 are coal.

Cost averages were:

•10 best coal plants -- 1.02 cents a kilowatt-hour;

•10 best nuclear plants -- 1.35 cents;

•And the lone gas plant -- 1.4 cents.

Recent national averages were reported as:

•Coal -- 1.87 cents a kilowatt-hour;

•Gas -- 2.56 cents, 37 percent higher;

•And oil -- 3.77 cents, 100 percent higher.

Competition favors increased use of coal.

Competition is a means of lowering the price of power.

Lower power prices are, in turn:

•A means of driving out imported oil at critical points in the economy;

•A means of keeping it out;

•And a way of making American workers stronger in the global competition.

The recent average rate for industrial power in the U.S. -- with coal delivering about 56 percent of supply -- is:

•37 percent below industrial Europe's average;

•49 percent below Germany, where subsidized coal and nuclear power predominate;

•And 73 percent below Japan, where nuclear and liquified natural gas predominate -- imported gas.

Electric power from coal is one of America's competitive and comparative advantages -- a global edge for the goods and services of American workers.

Americans require low-cost power because they have a load to pull. The economy their efforts create is the engine of the world economy.

Regional and national competition should:

•Extend the competitive reach of coal-fired power;

•Initiate a rise in use factors toward 75 percent;

•Establish in the rise a *de facto* expansion of the national generation base;

•And push down on power rates.

Competition to sell coal in the expanding market should, in turn, bring about:

•More efficient coal production;

•More efficient transportation;

•And more competitive coal prices.

The momentum thus imparted will carry forward.

To the point: As the time to add capacity comes on, coal will be growing more competitive as a power fuel in a competitive power market.

What else will be available as the time comes on?

Left to consider are the so-called renewable resources and the other fossil fuels.

For context: 1.7 trillion kilowatt-hours is:

•243 times the combined output of all non-hydro renewables;

•25 times oil;

•6.5 times natural gas;

•And about equal to coal.

Taking 1 percent from non-hydro renewables would require a doubling of capacity; and 5 percent would require a 12-fold increase of output.

The renewables to which the most publicized expectations attach are wind and solar power. In addition to the costs cited earlier, formal comment in the *Outlook* leads judgment toward these conclusions:

•Renewables can't foreseeably compete;

•Growth must disappoint expectation;

•Heavy intervention and big subsidies will be required for any sizeable increase in contribution.

The new *National Energy Policy Plan* is honest, if diplomatic, in finding as follows:

> "The scale and timing of market penetration will depend on further technological progress and the evolving regulatory framework."

In the fossil fuels, America's recoverable reserves compare as follows:

- •Oil -- 2 percent;
- •Natural gas -- 3 percent;
- •And coal -- 95 percent.

U.S. oil production is in decline. The coal reserve of more than 270 billion tons is the energy equivalent of world oil reserves.

Both the *Energy Policy Act* and the new *Policy Plan* are directed at achieving and maintaining energy security against geo-economic and geo-political disruption that can be caused by over-reliance on imported oil.

Putting imported oil into a sizeable share of new power would have wide and significant consequences on the world market and in world affairs; and consequences at home in both power and security. It also would require significant investment.

Imported oil should not be a consideration.

It comes down to coal and natural gas as the capacity-adding years come on.

The *Outlook* projects these will do as they have done -- the price of coal will trend downward and that of gas will fluctuate with an upward bias.

America's oncoming requirement is huge. All forms will have to contribute where they can best compete -- nuclear, natural gas, hydro-power, oil, coal, and, even, renewables.

The greatest marketing challenges are social and political, not technical and economic.

For an economic activity to succeed in a free society the following must apply:

- •Society must need it;
- •Society must have the resources to employ it;
- •And society must either demand it or consent to it.

The strongest strategies for realizing public consent -- like advances in technology -- are founded on that which exists, and they seek more effective combinations of resources.

The *Policy Plan* document sets a goal for 2010 of 60 percent efficiency for generation by technologies coming to maturity in this program.

The presentation *Vision 21* of the department's advanced research effort links the array of available technologies and the concept of the coal refinery.

Vision 21 reviews what you are achieving, and assays what can be be built on your achievement with diligent engineering -- no miracles necessary.

Here is what *Vision 21* foresees as in reach:

- •Energy and material resource complexes founded on coal and high efficiency technology;
- •From these complexes electric power, natural gas, other fuels, fuel additives, chemical products, process heat;
- •Plus useful and useable by-products from waste;
- •Plus conversion of emissions output to greater recovery of fuel from oil and gas fields;

•Because of efficiency and the increased revenue of added functions, lower cost electric power;

•And, in conjunction with natural sequestration, effective emissions rates at zero -- there or so close to it the calculation produces a decimal point followed by more than one zero before it reaches a number.

There will be alarums as long as there are emissions -- alarums of the kind meant to move someone's drama along.

Let us pledge to mobilize and move forward from an early date with the science and engineering that will achieve zero emissions.

Let us pledge a date certain -- say 2035.

And let's then vow not to keep that date and our purpose a secret -- not to let them be swamped by the clamor and excitement that can be raised by asteroids and other excursions.

If emissions are on the way to zero, there can be no reasonable objection to moving ahead with the business of the near- and mid-term.

In the meantime, both competition and the requirement for more electric power are coming on -- 21 percent by 2005, and 45 percent by 2020.

Expectations are that present coal capacity will carry the baseload through about 2005, and then the time to add capacity will begin to unfold.

Thus there are seven years in which to prepare the technologies both to serve and to compete one against the other in that market.

There is the technical and time-related matter of validation -- of proving performance by replication in additional and identical plants.

It may be that computer technology can be applied to give the proofs sought by validation.

After all, computer validation sped the most advanced of passenger aircraft to market -- the Boeing 777. It got the 777 into the air earlier and got it certified earlier.

Can we learn from Boeing? From the automakers and others?

We may have to seek enablement for consortia to complete the necessary steps; or to advance the 2035 pledge.

On the other hand, validation is related to the days of regulation, and to regulatory concepts like "prudency" and "used and useful."

In days to come, the evolution of electric power under the requirements of competition may well modify the needs of validation.

Some power producer that does not wait for for validation of regulatory thoroughness may come up a big winner in the competition. Competition may ultimately determine what is useful, and prudent.

Now only the matters of consent and preparedness remain.

Let's *think about what we can and can't do in some areas* important to informing opinion; and that, thereby, affect consent.

We can't censor the news to stem the drum-beat of asteroid scares, or of "alarums and excursions." In giving notice the press is only acting as watchdog.

Effective watchdogs bark at all noises and leave the assessment to others. Prudent householders want it so.

Hollywood increasingly ties drama to the extreme of alarums and allegations of motive in the news. The same is true for television entertainment and even some computer games.

We can't control entertainment.

But we can organize ourselves to speak the truth directly to the people.

If competition in electric power goes the way of deregulation in telecommunications, there will be a great deal of advertising. A great deal of the advertising will come to focus on price.

I have noticed that some power producers already are running positional ads on network television, including one major coal user. I'm sure others will follow.

Perhaps, as time goes by, those who use coal and advertise low price can be led to touch on related matters -- on things such as:

•Why the price is low -- the role of fuel;

•That those low prices come at the lowest comparable output of emissions;

•That the air is getting cleaner even as the price of power becomes cheaper;

•What technology will mean to the future;

•And, occasionally, on Project 2035.

I have noticed that the parent companies of at least three participants in this program are regular advertisers on national public affairs broadcasts -- on the discussion shows favored by those most interested in policy, the opinion leaders.

Perhaps, as time goes by, these technology dsevelopers can lead the parents to include in their public affairs efforts other items -- items such as the following:

•The higher efficiencies of the technologies they have made ready in this program;

•What these higher efficiencies will mean in power prices, in lower emissions;

•And an occasional reference to Project 2035.

Perhaps we can organize ourselves -- coal companies, power producers, transportation providers, equipment suppliers -- to bring about some of this through an existing arrangement, or through something new.

The U.S. Clean Coal Technology Program is the most successful joint venture ever undertaken on energy in the world -- federal, industrial, the states, and institutions.

You have worked wonders of engineering.

You in this room represent industrial and institutional entities that have invested $3.8 billion in these technologies -- about two-thirds of the cost.

I urge you to take from here to your chief executives this one thought, and to talk about it among yourselves: We need to tell this story to our fellow Americans now.

One half of one percent of $3.8 billion is $19 million.

What's do you think America's future is worth? One percent? Two?

If given the facts, I am confident they will give their approval.

We have only a few years to enable our world-leading research and development to ensure the nation's continuing preeminence as the world's number #1 supplier of low-cost, environmentally friendly energy.

I say let's look to preparedness and get started.

PANEL SESSION 3

Issue 3: Financing Challenges
for CCTs

LEAST-COST STRATEGY FOR ENVIRONMENTAL COMPLIANCE IN THE ENERGY SECTOR
Case and Least Cost Studies: Shanghai and Henan

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ABSTRACT

This paper presents the results of a World Bank study, which evaluated the cost-effectiveness of environmental control technologies and suggesting the least-cost alternatives for the Shanghai metropolitan area and Henan province. Assessment period is 1997 - 2020. Case studies and least cost optimization study has been done considering:

- *least cost expansion program*
- *environmental emissions and*
- *environmental externalities.*

Environmental control options, which were considered included: coal washing, electrostatic precipitators, wet and simplified flue gas desulfurization, atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion, integrated gasification combined cycles and liquefied natural gas-based combined cycles in power sector. The cost-effectiveness of these options in removing specific pollutants was compared with non-power options such as: use of briquettes, gas and/or washed coal by industrial and residential users. These analyses will help policy makers to select the most cost effective way to reduce pollution in the Shanghai and Henan area.

The results of the study suggest that:

- *Particulate emissions both in Shanghai and Henan come mainly by non-power sector (78% and 84% respectively) and considering the impact of particulate emissions indoor or close to the human residence, countermeasures to reduce particulate emission in residential and industrial sector have greater effect in cost effective manner*

- *total particulate emissions from power sector in Shanghai and Henan will decline due to actions taken including utilization of higher quality coal, retirement of small, inefficient power plants and utilization of high efficiency ESPs in the new coal-fired power plants; for further reduction of particulate, use of gas and briquettes in households, coal washing and installation of ESPs in existing small power plants are cost-effective*

- *the most cost-effective options for controlling SO2 emissions in Shanghai are: use of coal briquettes in the residential and industrial sector, simplified FGD in selected existing power plants which burn medium-to-high sulfur coal, and coal washing*

- *the most cost-effective options for controlling SO2 emissions in Henan are: simplified FGD installed to all units which burn medium-to-high sulfur coal and briquette use in rural household*

- *for NOx reduction, combustion tuning/optimization and low NOx burners are most cost effective options*

- *in Shanghai, LNG power plants may provide a cost-effective way to reduce pollution, but their cost-effectiveness is very sensitive to the way they are dispatched (capacity factor)*

- *in Shanghai, where coal is imported from other provinces for long distance, coal washing emerges as a desirable option, especially when the synergistic effects of particulate and sulfur reduction are taken into account. However, in Henan, where most of the coal used produced local and contain less sulfur, coal washing appeared to be not so economical options either in power and non-power sector*

- *by using externality assessment, each pollutant (TSP, SO2 and NOx) can be converted to common indicator to put priority by its cost effectiveness and capacity of removing pollutant. According to this analysis, briquette and gas use in household and industry sector has greater potential to reduce pollutants at lower cost. In power sector, combustion tuning, ESP rehabilitation, low NOx burner, accelerating retirement of small plants and simplified FGD has large potential to reduce pollutants at lower cost*

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1. INTRODUCTION

China is the third largest energy producer and the second largest electricity producer in the world. Coal is the most important source of energy accounting for 75% of total energy production. Coal-fired power plants provide more than 90 percent of thermal power generation, which provide around 80 percent of the total electric power production.

Despite the strong growth in electricity output, most area of China continue to suffer from severe power shortages. The rapid economic growth will put tremendous pressure on China's electric power industry to avoid yet worse shortages. China's electric power construction program for the 1990's will certainly be the world largest.

Thermal power production currently accounts for about one third of China's coal consumption, and the share is expected to increase. Improvements in the efficiency of coal use in this sector not only alleviate pressure on the coal production and transportation system, but also have a major impact on particulate, sulfur, nitrogen and carbon dioxide emissions.

The achievement of economies of scale in thermal power production, through expanded development of large generating units, is a priority because of the recent rapid growth of small coal-fired power plants in unit sized of 50 MW or less. While national policy emphasized the addition of 300 MW and 600 MW units, new projects have lagged behind demand and local governments are continuing to invest in large number of new small plants, largely due to difficulties in mobilizing the necessary investment resources.

China has made substantial progress in particulate control through deployment of high efficiency electrostatic precipitators. Also, it has started to employ sulfur dioxide control devices in areas where ambient air quality standards require them, such as in Shanghai and southwest China. Several pilot flue gas desulfurization (FGD) projects have been implemented in areas where the sulfur content of coal is relatively high, such as: Luohang and Chengdu power plants in Sichuan Province, and the Japanese-assisted projects in Huandao, Shangdong and Taiyuan, Shanxi.

Recently, the Chinese Government initiated additional efforts to curb air pollution especially from coal-fired facilities of the power sector. A number of initiatives which focus on air pollution include:

- intention to keep particulate emissions at about 3.8 million tons (1992 level)
- in June 1994, the government announced that it will spend about $2 billion over the next seven years on an environmental program aimed at keeping SO2 emissions at a level of 15 million metric tons a year as part of a comprehensive program of acid rain abatement

- also, an SO_2 emission tax (ranging from Yuan 0.15 to 0.2/kg of SO_2) is being experimented in several provinces and municipalities; furthermore, a tax of Yuan 0.04/kg of SO_2 is applied on emissions where the 1982 environmental standards are exceeded in all provinces.

The Shanghai metropolitan area with its rapid economic growth is representative of both shortage of electric power and urban pollution in China. Henan province is the most populated province in China and depend on domestic coal as energy source. The World Bank, with the assistance of BERI, carried out this study to assess the cost-effectiveness of environmental control options. The study started from power sector in Shanghai, but finding important contribution from other sectors including industry and residential sectors, cost-effectiveness of control options have been analyzed in a limited way in Shanghai. In Henan study, scenarios and options in other sectors have been addressed more comprehensive manner.

2. BACKGROUND

2.1 Energy Consumption in Shanghai and Henan

There have been almost no commercial primary energy resources found in Shanghai therefore there are no primary energy production in the municipality. All the primary energy consumption depends on imports from other regions in China and even abroad.

Shanghai, as China's largest municipality and most important industrial, commercial and financial center, the per capita energy consumption is much higher than the national average level. In 1994, the per capita energy consumption in the municipality was 3.125 ton coal equivalent, which was more than three times the national average;

Most of energy was consumed by industry while the residential energy consumption proportion was low. In 1994, the total industry energy consumption represented 78.4 percent of the total energy consumption in the municipality. Residential energy consumption only represented 8.3 percent of the total. Energy utilization efficiency is relatively high compared with other places of China, but the potential of energy conservation is still large in the standard of developed countries.

In Henan province the total production of primary energy amounted to 80.709 billion tons coal equivalent, in which raw coal accounted for 80.36 %, crude oil 15.61%, natural gas 2.29 % and hydropower 0.77 % in 1990. In 1995, the total raw coal output amounted to 92.79 million tons, which ranked the second in China. The crude oil output was 7.64 million tons, natural gas was 1.167 billion cubic meters and hydropower was 1.66 TWh.

The features of energy consumption in Henan can be summarized as following: The standard of per capita energy consumption is lower than the national average level. In

1995, the per capita energy consumption in the province was 602 kg coal equivalent, only representing 69.7 percent of the national average;

Most of the energy consumed in the province is coal. In 1995, the total coal consumption reached 67.13 million tons consisting of 87 % of the total primary energy consumption of the province.

Most of energy was consumed by industry while the residential energy consumption proportion was low. In 1995, the total industry energy consumption represented 67.9 percent of the total energy consumption in the province of which 66.4 percent was consumed in metallurgical, chemical, construction material and mining sectors. Residential energy consumption only represented 18.6 percent of the total in the province. Energy utilization efficiency is relatively low and there is a large room for energy conservation.

2.2 Electric Power System in Shanghai and Henan

By the end of 1995, the Shanghai Electric Power Grid included 12 power plants with installed capacity of 6,543 MW consisting of one oil-fired power plant (2 x 125 MW) and the remaining coal-fired. Plant of 100 MW or more (including 2 X 600 MW units, 8 X 300 MW, 9 X 125 MW and one 100 MW) represented 4,825 MW, which is 73.7 percent of total capacity. Total electricity generation in 1995 was 30.8 TWh.

As China's largest industrial and commercial center, the development of power industry in Shanghai is facing great challenges. It needs to increase power supply to meet growing demand while satisfying increasingly tight environmental requirements. Although installed generating capacity increased significantly in recent years, it has not matched the demand growth. For example, in 1995 it experienced load shedding during 30 days. Severe constraints were imposed on industry, which had to reschedule work and curtail production.

In the end of 1995, the total installed capacity of Henan province reached 10 GW in which 9.5 GW was thermal and the rest was hydropower. The total electricity generations were 55 TWh in which thermal was 53 TWh, hydropower was less than 2 TWh.

Electricity consumption of the province accounted for 54 TWh in 1995, among which 78 percent to industry, 8 percent to agriculture, 8 percent to residential, 7 percent commercial and other municipal customers in the cities, as well as the transport and telecommunication sectors.

2.3 Environment in Shanghai and Henan

According to the "Shanghai Environmental Bulletin in 1994," the annual average concentration of SO2 in the municipality was 0.038 mg/m3, which is below the World health Organization's (WHO) standard of 0.06 mg/m3 but the concentration of TSP was 0.247 mg/m3, which exceed the limit of the WHO standard of 0.06 mg/m3. Acid rain is common as indicated by the average pH of the precipitation, which reached 5.42 in 1994.

Since the early 1980s, the SO2 emissions released to the environment in Shanghai has increased drastically, mainly because of increased coal burning. In 1994, the coal consumed in Shanghai was 35.13 million tons, which produced 451.9 thousand tons of SO2. Power plants were emitting 325.5 thousand tons of SO2, which is approximately 72 percent of the total SO2 emissions in Shanghai.

Shanghai municipality issued stringent environmental regulations and increased efforts to enforce existing regulations by imposing fines on industrial units and power plants which do not comply with emission standards and/or imposing use of flue gas desulfurization for all new plants. It is also cooperating with the World Bank to apply the "bubble concept" to control sulfur dioxide emissions while minimizing costs.

Henan Province faces a serious environmental problem. In particular urban areas remain the main centers of pollution generation, and these are rapidly expanding to rural areas. The scale and degree of ecological damage is increasing. The environmental pollution and ecological damage is becoming a constraint on the development of the economy and society, becoming the focus of the public attention.

Coal burning is a major cause of air pollution. Ambient air quality of dust and sulfur dioxide are exceeding limits of WHO and national standard and the situation is gradually worsening in major cities in Henan province. As the rapid increase of motor vehicle in urban area, automobile emissions are also increasing. As a result, NOx concentration levels are worsening each year as well.

Table--The Annual Mean Value of Ambient Concentration of SO2, TSP and NOx Emissions In Major Cities of Henan Province Unit: mg/m3

	1993			1996		
Name of City	SO2	TSP	NOx	SO2	TSP	NOx
Luoyang	0.155	0.365	0.056	0.183	0.452	0.052
Anyang	0.095	0.403	0.065	0.105	0.571	0.077
Jiaozuo	N/A	N/A	N/A	0.087	0.536	0.052
Zhengzhou	0.067	0.418	0.071	0.060	0.469	0.077
Kaifeng	N/A	N/A	N/A	0.042	0.447	0.049
Pingdingshan	0.049	0.336	0.036	0.023	0.302	0.043

Source: China Environment Yearbook 1995
China Environment Yearbook 1997

3. METHODOLOGY

The methodology applied in the Shanghai and Henan case study includes an approach:

A. estimate the cost-effectiveness and capacity of emissions reduction of key environmental control options

B. assess current and future trend of environmental externalities of .Shanghai and Henan province and integrate pollutants (TSP, SOx and NOx) to common indicator to give priority to each options in power and non-power sectors

C. a least cost optimization study was carried our to identify the combination of each options to achieve certain policy target.

Steps taken were as follows:

1. Establish base case scenario
2. Generate its environmental emissions
3. Identify alternative emission control options
4. Assess cost-effectiveness and capacity of reduction of alternative scenarios
5. Assess current and future trend of environmental externality
6. Run and assess the least cost optimization model to achieve given target

The following paragraphs describe these steps in more detail.

3.1 Establish base case scenario

The base case scenario is the official or latest power development program (least-cost plan), which was developed using the WASP (Wien Automatic System Planning) model for Shanghai and GESP II (Generator of Electric System Planning II) for Henan. The least cost plan takes into account, among others, the characteristics of the existing power system, the retirement schedule, the projected demand and the viable supply options.

3.2 Assess the environmental emissions of the base case power development program

This involves generation of the emission release rates. The most common pollutants being estimated are: total particulate (TSP), SO_2, NOx, and CO_2. In addition to the pollutants out of consumer sites, an attempt is made to estimate the pollution rates throughout the fuel chain, including the fuel extraction (e.g., coal mining), processing (e.g., coal cleaning or oil refining) and transportation. In the Shanghai case study, the

EM model[1] (Environmental Manual for Power Development) was used to generate environmental emissions. In Henan study, the GESP II model generate emissions for the power sector and EM model was used to generate emissions to non-power sectors.

3.3 Identify alternative emission control options

Under this step, all alternatives for emission control are identified. These include:

- specific options, which can be applied on existing power plants such as use of cleaned coal, retrofit control technologies such as upgrading of electrostatic precipitators (ESP), combustion tuning, low NOx burners, selective catalytic reduction (SCR), flue gas desulfurization (FGD).

- fuel switching (e.g., from coal to gas or LNG) when these fuels are available

- rehabilitation of power plants which results in efficiency improvement and emission reduction

- retirement of smaller inefficient plants and replacement with larger and more efficient ones

- advanced coal utilization technologies such as atmospheric fluidized-bed combustion (AFBC), pressurized fluidized-bed combustion (PFBC), integrated gasification combined cycle (IGCC)

- emission reduction options outside the power sector; in sectors such as the residential and industrial, which may:
  - ⇒ use briquettes
  - ⇒ switch from coal to gas or LPG
  - ⇒ use washed instead of raw coal

Based on careful review of the above, as well as other options, which may be applicable for the specific power system being evaluated, the most viable and promising options were identified for further evaluation. These options, each one separately or in combination with each other, form the basis for scenario analysis.

[1] The EM model was developed by a number of bilateral agencies from Germany (BMZ and GTZ), Netherlands (DGIS), Switzerland (BAWi) and United Kingdom (DFID) with the coordination by the World Bank.

3.4 Assess the Cost-Effectiveness of Alternative Scenarios

For each scenario, the system-wide costs (net present value: NPV, including the costs of all power facilities including environmental control equipment), the corresponding reduction of pollutants and the cost-effectiveness ($/ton of pollutant removed relative to the baseline case) were estimated.

3.5 Environmental Externality

The environmental externalities for Shanghai and Henan were estimated using the externality values of New York Externality Model (Rowe et. al., 1994) adjusted for location, emission level and population. The $/ton/person values for local area (the area within 30 km from the site), regional area (location between 30 and 100 km of the site) and distant area (beyond 100 km and up to 500 km from the site) have been taken from the New York Model. The value of per capita GDP is taken from "World Development Report 1996 - From Plan to Market-" using purchasing power parity. The values are multiplied by numbers of affected individuals to obtain total values for the impacts per unit of time. The individuals affected are population in related areas. Population of different areas were estimated based on the statistic books of related regions. Based on emissions and their unit economic cost and population, the economic externality costs of the emissions at present and future are calculated.

4. Key findings

The key findings of the study focus on the cost effectiveness of particulate, SO2 and NOx control, synergy in controlling more than one pollutant at a time, externality analysis and methodological issues.

4.1 Particulate Control

For particulate emission we found the common current status and trend in the future both in Shanghai and Henan. The main sources of particulate are industrial and residential sectors which contribute approximately 78% and 82% of the total, respectively with the remaining of 22% and 18% contributed by the power sector, respectively (Figure 1). Within the power sector, 90% and 73% of the particulate (20% and 13% of the total) are coming from small power plants (less than 125 MW), and the larger unit size plants (larger than 125 MW) emit only 10% and 27% (2% and 5% of the total). Furthermore, the power sector contribution to particulate emissions is expected to decline significantly in the period 2010-2020 (9% and 7% in Shanghai and Henan, respectively; see Figures 2 and 3). This decline is mainly due to the following actions, which have been made by the local authorities:

- retirement of smaller power plants (less than 125 MW), and

- in the future, utilization of larger power plants equipped with efficient ESPs
- utilization of higher quality coal in new power plants (policy adapted by Shanghai Municipal Electric Power Co. in 1996).

For the projected trends of declining particulate to materialize, it is important that plant retirement proceeds as scheduled and construction of small power plants (other than cogeneration units with environmental controls) are banned. Recent statistics indicate that the rate at which small power plants are being built has not changed; for example 11 GW of power plants in the 6-75 MW range were added throughout China in the period 1991-1995 (representing 20% of the new capacity added).

For further reduction of particulate, considering the impact of particulate emissions indoor or close to the residence, countermeasures to reduce particulate emission in residential and industrial sector have greater effect in cost effective manner (Figure 4) such as using briquettes or gas for cooking and heating, or using briquettes in industry. Assessment of the various particulate control options in Shanghai and Henan (including power and non-power applications) suggests that the most cost-effective options are in the industrial and residential sectors, especially:

- use briquettes for rural household and industry
- use gas for urban household
- use of washed coal; 10-15% ash instead of the commonly used coal with 30-35% ash
- replacement of small inefficient facilities with larger more efficient plants with high efficiency electrostatic precipitators (ESP).

Further reduction of particulate in power sector will require installation of new electrostatic precipitators (ESP) or upgrading of ESPs in existing power plants. Particulate removal in the power sector ranges in terms of maximum achievable volume of particulate reduction and cost-effectiveness. As it is shown in Figure 5 (Shanghai):

- more than one million tons of TSP can be removed during the period 1997-2020 at a cost of approximately 300 $/ton of TSP removed, if high efficiency[2] ESPs are retrofitted to existing cogeneration plants
- an additional 3,000 tons of TSP can be removed during the same period (1997-2020) at 750 $/ton of TSP removed, if high efficiency[3] ESPs are retrofitted to five 25 MW power plants which are operating in Shanghai

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[2] ESP with 99.9% collection efficiency replaces existing ESP which is only 92% efficient; 10 year life is assumed

[3] ESP with 99.9% collection efficiency replaces existing ESP which is only 96.25% efficient; 10 year life is assumed

- the cost of retrofitting ESPs on existing power plants of 100- 125 MW averages at 1,500 $/ton, while coal washing (which is not primarily intended for particulate control) reduces particulate at 2,200 $/ton of TSP removed.

It should be noted that installation of ESPs or ESP upgrades in existing power plants is not included in the scenarios shown in Figure 1a. However, if retirement of the smaller power plants is delayed, full compliance with particulate standards should be required. The cost-effectiveness of installing ESP in existing power plants (see Figure 5) is 300 to 1,500 $/ton.

In Henan study cost effectiveness of removing particulate emissions from residential sector and industrial sector are compared to the power sector options (Figure 4). It should also be noted the figure shows the emission reduction cost effectiveness and does not take into account the distance from emission sources (in case of domestic very close distance and in power sector usually distant from high stack and in industrial in the middle) thus the impact of the emissions from each sector should different.

- when briquette replaces coal used in household 7 million tons of TSP emissions will be reduced at a cost of $120/ton of TSP during the period 1997-2020

- when gas replaces coal used in household over 10 million tons of TSP emissions will be reduced at a cost of $330/ton of TSP

- briquette use in industry could reduce the 2.7 million tons of TSP emissions at a cost of $800/ton

- more than one million tons of TSP can be removed at a cost of approximately 200 $/ton of TSP removed, if high efficiency[4] ESPs are retrofitted to existing plants

4.2 SO_2 control

Current status of SO2 emissions in Shanghai and Henan are different due to difference in usage in power sector/non-power sector and sulfur content in coal. The power sector accounts for 72% and 44% of the total SO_2 emissions in the Shanghai and Henan, respectively. In business as usual case in Henan, contribution from power sector will be tripled and accounting 53% in 2020. The remaining 28% and 57% are due to industrial and residential sectors in Shanghai and Henan, respectively (Fig. 6 and 7). Figure 8 shows that the impact each of the following options has a significant impact on total SO_2 emissions in Shanghai:

- wet FGD in all large existing and new power plants

[4] ESP with 99.9% collection efficiency replaces existing ESP which is only 92% efficient; 10 year life is assumed

- simplified FGD in all large existing and new power plants
- pressurized fluidized-fed combustion (PFBC), and
- integrated gasification combined cycle (IGCC)).

Figure 4a shows the cost-effectiveness of these options range from 700 - 1600 \$/ton, and. more cost-effective options which should be pursued first (the cost-effectiveness in parenthesis):

- use of coal briquettes in the industrial and domestic sectors (150 \$/ton of SO_2 removed)
- FGD in existing power plants which burn medium-to-high-sulfur coal, such as 2% sulfur and 30% ash (500 \$/ton of SO_2 removed)
- use of washed coal in industry and existing power plants (400 - 500 \$/ton of SO_2 removed)

However, as it is also shown in Figure 9, the maximum SO_2 reduction potential of these options is limited to a cumulative of 6,000 tons for the planning period (1997-2020). Simplified FGD can remove additional 8,000 tons at a cost of \$700/ton, and Wet FGD can remove over 10,000 tons at a cost of \$900/ton. The advanced technologies such as IGCC and PFBC have higher cost of removal of SO2 at the current estimate of cost, however these technology also can reduce other emissions: TSP, NOx and CO2, which will be discussed later.

The least-cost development plan included 10,400 MW of LNG-fired capacity which will be used mainly to satisfy peak load demand (capacity factor approximately 30% for the combined cycle units and 15% for the simple gas turbine cycle units). When we assume all new coal-fired power plants added after 2005 would be replace by LNG combined cycle ("LNG scenario"), economic dispatching results in approximately 50% capacity factor for LNG plants and the cost-effectiveness for SO2 removal is \$400/ton.

When we assume that LNG-fired power plants are dispatched at a 65% capacity factor (sometimes required by "take-or-pay" contracts), the cost effectiveness of SO2 removal becomes \$1200/ton which is among the highest including wet FGD options.

It is therefore concluded that LNG could be a cost-effective option for lowering SO2, but careful consideration should be given to the way LNG plants are dispatched which may be impacted by the fuel supply contractual terms and conditions.

In Henan, as Figure 10 shows, the most cost effective options to control SO2 emissions is in power sector as well as briquette use in household sectors:

- Simplified FGD to all units which burn medium-to-high sulfur coal can remove 1.7 million tons of SO2 for the period of 1997 - 2000 at a cost of \$800 /ton of SO_2 removed

- Wet FGD to all units which burn medium-to-high sulfur coal can remove over 2.2 million tons at a cost of $1,150/ton
- Briquette use in rural household can remove 500,000 tons of SO2 at a cost of $800 /ton

Coal Washing in Henan is not as cost effective as it is in Shanghai. In power plant coal washing can remove 800 thousand ton of SO2 at a cost of $1,300/ton. But in industry and household sectors, coal washing can remove only 100,000 ton and 30,000 ton at relatively higher cost of $2,300/ton and $3,300/ton, respectively.

Advanced Clean Coal Technology such as AFBC, PFBC and IGCC can be applied only to the new units and still rather high cost to remove SO2 emissions. All three options can remove around 1 million ton of SO2 during 2003 - 2020 at costs of $2,300/ton, $3,200/ton and $4,000/ton of SO2 removal, respectively.

Gas use in urban household appeared to be a high cost options, but considering the immediate health impact by indoor air quality, and the convenience of use of gas in household use need to be taken into account as other aspects to promote gas use in household.

On the other hand, it also should be noted that since gas resources are limited in Henan, gas need to be derived from coal. Gas use in urban household would increase TSP, SOx NOx and CO2 emissions in Industry Sector to produce gas.

4.3 NO2 control

Power, industry and transportation sectors contribute 42%, 37% and 11% of the NOx emissions in Henan, respectively (Fig. 11). Emission from transportation sector rapidly increasing and will account for 15% by 2020, when power and industry sector account for 39% and 37% respectively.

In Henan study NOx control options are examined, and some options in power sector turned to be very cost effective options to control NOx as shown in Figure 12:

- Combustion tuning/optimization applied to all new and existing plant can remove 500,000 tons of NOx for the period of 1997 - 2000 at a cost of $20 /ton of NO2 removed
- Low NOx burner is already incorporated in the design of new boiler in business as usual case, but if it is retrofitted to existing plants, it can remove additional 300,000 tons of NOx at a cost of $100/ton

When further reduction of NOx is required, SCR installation to new power plants can remove additional 400,000 ton of NO2 at a cost of $1,200/ton, which is still lower than NOx control measures in other sectors. Small power plant retirement is accelerated, it can reduce 200,000 tons of NO2 at a cost of $3,500/ton. AFBC or PFBC if applied to new units after 2003, either of them can reduce 200,000 tons of NO2 at a cost of $11,000/ton and $14,000/ton, respectively. IGCC can remove 360,000 tons of NO2 at a cost of $11,000/ton when applied to new units after 2003.

In the industry sector, when briquette replace raw coal, it can reduce 600,000 tons of NOx emission at a cost of $2,700/ton. When briquette is used at rural household, it can reduce 100,000 tons of NO2 at a cost of $3,750/ton. Three way catalyst applied to transportation sector can only reduce 70,000 ton at a cost of $7,600/ton, although it should be noted that the catalyst reduce not only NOx but also reduce hydro-carbon from vehicles.

4.4 CO2 emissions

Power, industry, domestic and transportation sectors contribute 33%, 39%, 19% and 6% of CO2 emissions in Henan. CO2 emissions from power sector will be tripled by 2020 while the total emissions will be doubled.

Countermeasures to CO2 in household and industry sectors are cost effective. Briquette use at rural household replacing coal can reduce 25 million tons of CO2 during 1997 - 2020 at a cost of $15/ton of CO2, while briquette use in industry can reduce 70 million tons of CO2 at the same period at a cost of $25/ton of CO2.

In power sector, accelerating retirement of small inefficient power plant is the most cost effective way, and it can reduce 33 million tons of CO2 at a cost of $25/ton. IGCC can remove 15 million tons of CO2 at a cost of $260/ton.

4.5 Least Cost Optimization Analysis

To achieve a certain policy target such as stabilizing emissions or 20% decrease of emissions, the least cost scenario is usually the mixture of the options. Each option may excludes each other (like choosing PFBC or IGCC) or can be combined (like low NOx burner and high efficiency ESP and FGD). The computer model picks up combinations of options so that it becomes the least cost option to achieve the policy target.

The policy target could be stabilizing all emissions (TSP, SO2 and NOx) or each at a time. Single emission stabilization scenarios at power sector is discussed first and then all emissions stabilization scenario for both power and non-power sector later.

i) TSP emissions stabilization scenario (Fig. 13)

New ESP will be installed in small local government and private owned plants (6MW and 10 MW) and small plants owned by Electric Power Company of Henan (EPH), which are scheduled to retired after 2005 to the level of 200 mg/Nm3 at each plant and reduce the total emissions from power sector to 80% level of TSP emissions in 1997.

ii) SO2 emissions stabilization scenario (Fig. 14)

Simplified FGD will firstly installed to existing plants using low and medium quality coal, and then wet FGD will be installed to existing plants using low and medium quality coal. Both type of FGD will also be installed to new plants using low and medium quality coal to stabilize the SO2 emissions level at 1997 level.

iii) NOx emissions stabilization scenario (Fig. 15)

Combustion tuning and optimization will be applied to existing and new plants as well as installing low NOx burner to existing plants first, and at later stage (after 2010) SCR need to be installed to new plants to stabilize the NOx emissions level at 1997 level.

iv) All emissions stabilization scenario (Figs. 16 through 19)

In power sector, first actions to be taken will be combustion tuning/modification for all plants, Low NOx burner retrofit at existing plants, and combination of simplified/wet FGD and combustion tuning/low NOx burner. Installing high efficiency ESP to small plants play reduced roles since the small plants will be eliminated by 2020, and FGD can remove particulate from existing large and middle size plants as well as removing SO2. Existing large and middle size plants should be retrofitted some measures by 2010.

After 2010, combination of simplified/we FGD and SCR need to be installed to new plants. Small plants and large and middle size plants without further environmental control will be eliminated by 2020.

Electricity cost will be increased by 12% from 0.262 Yuan/kWh (3.16 cent/kWh) to 0.294 Yuan/kWh (3.54 cent/kWh) in all limitation case as shown in Fig. 20.

In non-power sector, we have not established the optimization model, the emission reduction strategy was created manually from the results of the case study and concentrated on stabilizing SO2 and TSP emissions.

- In industry sector, replacing 15%, 65% and 90% of raw coal by briquettes by 2000, 2010 and 2020 respectively
- In Urban household, replacing 25%, 65% and 80% or coal by coal gas by 2000, 2010 and 2020 respectively
- In Rural household, replacing 20%, 40% and 65% of raw coal by briquettes by 2000, 2010 and 2020 respectively

4.6 Environmental Externality Analysis and Synergy of Emission Controls

The above analyses assess the cost-effectiveness of environmental control options focusing on one pollutant at a time. However, there are options, which contribute to the reduction of more than one pollutant, such as: coal washing, FGD, advanced power generation technologies and switching from coal to oil or natural gas. These options require methodologies, which take in account all the environmental benefits and spread the costs appropriately. While such analysis was not carried out in this study, it will be incorporated in future assessments.

One way of integrating the benefit and comparing cost-effectiveness is to calculating environmental externality by each unit of pollutant ($/ton) and use is as converting factors to compare the impact each other. For example, by using New York State externality values and adjusted by GDP per capita and the populations to the area of Shanghai and Henan we get (Fig. 21):

	$ 1996/ton	Shanghai		
	Local	Regional	Distant	Total
TSP/PM10	569	807	527	1902
SO2	137	120	133	389
NOx	159	141	154	455

	$ 1996/ton	Henan		
	Local	Regional	Distant	Total
TSP/PM10	25	182	733	940
SO2	6	27	183	217
NOx	7	32	214	252

The same amount of emissions either TSP, SO2 or NOx causes around twice as much as environmental externalities in Shanghai than in Henan, because of higher population density especially in Local (within 30 km from the source) and Regional (30 - 100 km from the source) areas. In Distant (100 - 500 km from the source) area, higher externality is observed because more people live in the rural area in Henan.

The particulate emissions caused around 4.3 - 4.9 times externality than the same weight of SO2 emissions. NOx emission causes slightly higher (1.17 times) externality than the same weight of SO2 emissions. By using these factors, TSP and NOx emissions are converted to the SO2 equivalent, and the cost effectiveness and emissions reductions can be compared as integrated pollutant control systems priority.

Figs. 22 and 23 shows the results of the cost effectiveness of pollution control options in non-power sector and power sector in Henan, respectively.

In non-power sector, options can remove lager amount of pollutant at lower cost due to large amount of TSP removal capacity:

- briquettes for rural household can remove 19 million ton of SO2 eq. at a cost of $21/ton of SO2 eq.
- coal washing for household can remove 2.4 million $39/ton of SO2 eq.
- briquettes for industry can remove 14 million ton of SO2 eq. at a cost of $115/ton of SO2 eq.

- gas for urban household can remove 8.4 million ton of SO2 eq. at a cost of $118/ton of SO2 eq.
- coal washing for industry can remove 1.7 million ton of SO2 eq. at a cost of $130/ton of SO2 eq.

In power sector:

- combustion tuning is the lowest cost option at $14/ton of SO2 equivalent removal and can remove 570,000 ton of SO2 equivalent during the period of 1997 -2020
- ESP rehabilitation of existing small units can remove 5 million ton of SO2 eq. at a cost of $41/ton of SO2 eq.
- low NOx burner can remove 350,000 ton of SO2 eq. at a cost of $87/ton of SO2 eq.
- accelerating retirement of small units can remove 3.5 million ton of SO2 eq. at a cost of $220/ton of SO2 eq.
- simplified FGD can remove 5.1 million ton of SO2 eq. at a cost of $280/ton of SO2 eq.
- when the World Bank's new guideline is applied to all new units of ESP (50 mg/Nm3), it can remove 600,000 ton of SO2 eq. will be removed at a cost of $450/ton of SO2 eq.
- wet FGD can remove 5.6 million ton of SO2 eq. at a cost of $470/ton of SO2 eq.
- coal washing can remove 2 million ton of SO2 at a cost of $480/ton of SO2 eq.
- SCR can remove 450,000 ton of SO2 eq. at a cost of $1,050/ton of SO2 eq.
- AFBC, PFBC and IGCC can remove around 1.5 million of SO2 eq. at costs of $1,600/ton, $2,100/ton and $2,300/ton of SO2 eq.

Since we have estimates of pollutant emissions, we can calculate the externality from each pollutant by multiplying externality values per ton of each pollutant. Henan is suffering $2.5 billion of externality and the value will be doubled by 2020 in business as usual case. Around 85% of externality is caused by particulate emissions, and highest priority should be put in reducing particulate emissions (Fig. 24). With in the power sector of Henan, particulate emissions are causing high proportion of externality (72%) but is declining gradually. By 2020 particulate still is the highest (44%) but the SO2 is playing larger role (34%) than today (Fig. 25).

Externality in Henan (M$/year)

	1997	2000	2010	2020
TSP	2201	2423	2749	3898
SO2	182	201	312	433
NOx	179	195	276	360
Total	2562	2819	3337	4691

Externality by Power Sector in Henan (M$/year)

	1997	2000	2010	2020
TSP	394	388	367	294
SO2	79	87	151	231
NOx	75	80	105	139
Total	548	555	624	664

In power sector of Shanghai, SO2 emissions will play dominant role (around 60%) in 2020 followed by NOx emissions (30%), although currently particulate emission is the highest contributor (around 50%) and SO2 contribute 35% of externality (Fig. 26).

Externality by Power Sector in Shanghai (M$/year)

	1997	2000	2010	2020
TSP	223	226	118	77
SO2	168	187	233	365
NOx	83	128	143	198
Total	473	542	494	640

Current status and future trend of externality from each pollutant should be taken into account as well as cost effectiveness of options in forming environmental control strategy.

5 Methodological Considerations and Next Steps

Scenario analysis proved very helpful in identifying the most cost-effective environmental control options for Shanghai and Henan. Least cost optimization analysis can provide combination of strategies to achieve the specific environmental policy target at minimum cost. Also, the externality analysis provides useful input to policy-makers on how to target future policies to achieve the desirable results.

In future assessments, the methodology could be enhanced further by:

- improving impact analysis by taking account of dispersion from source of emissions and damage to the health, production through improved externality analysis
- learning curve analysis for advanced technology, and new technology to local market (international price .vs. domestic price)
- developing methodology to distinguish marginal and average effect of cost effectiveness and externality
- providing complete options for industrial and household sectors comparison and developing methodology to analyze multi-sectors more integrated manner
- addressing CO2 externalities to compare whether it can be integrated to other pollutant
- addressing cost effectiveness comparison with renewable and nuclear options
- evaluating the impact of options such as demand side management and market-based mechanisms on environmental control cost-effectiveness
- developing a least-cost plan by using environmental externalities for the most common pollutants

The World Bank, working with the Government of China, is planning to carry out in depth Clean Coal Technology Assessment for China and case studies in other provinces of China which expand the methodology described in the Shanghai and Henan study.

Fig. 1: TSP emissions in Henan, 1997
Total emissions: 2,391,000 ton

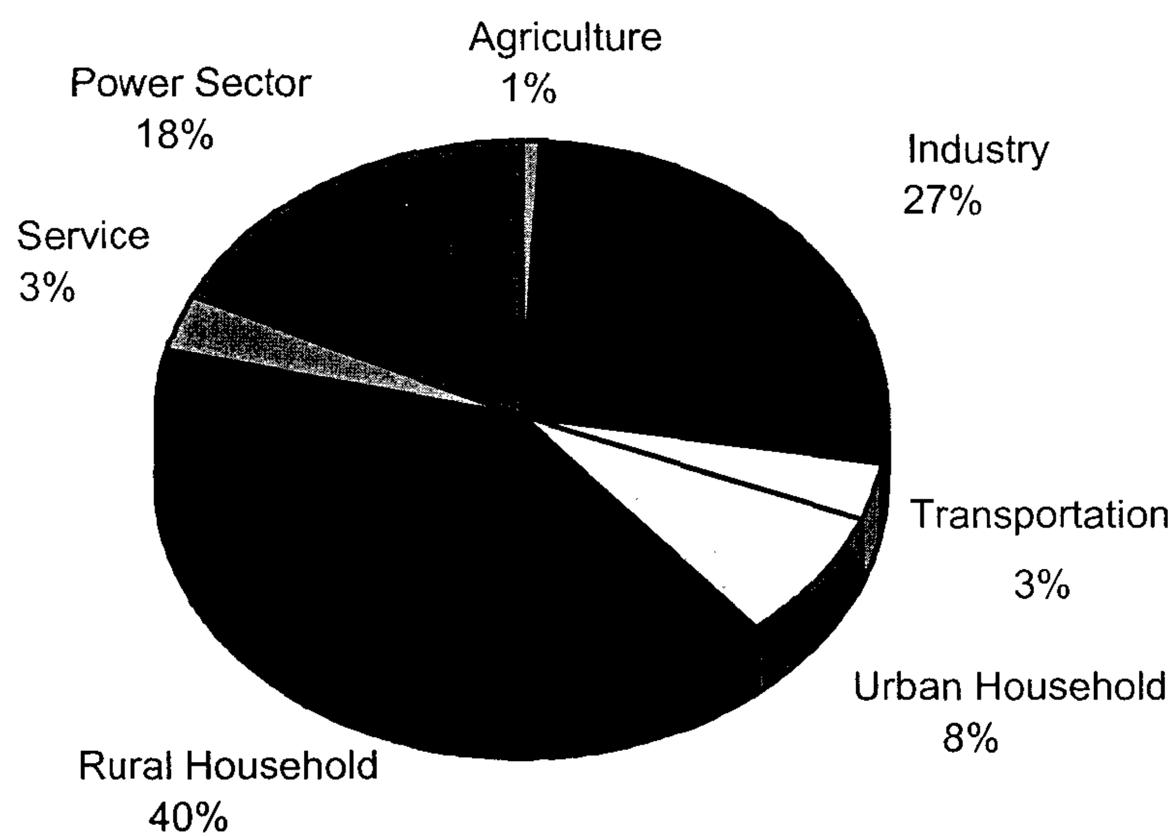


Fig. 2: TSP Emissionfrom Power Sector in Shanghai

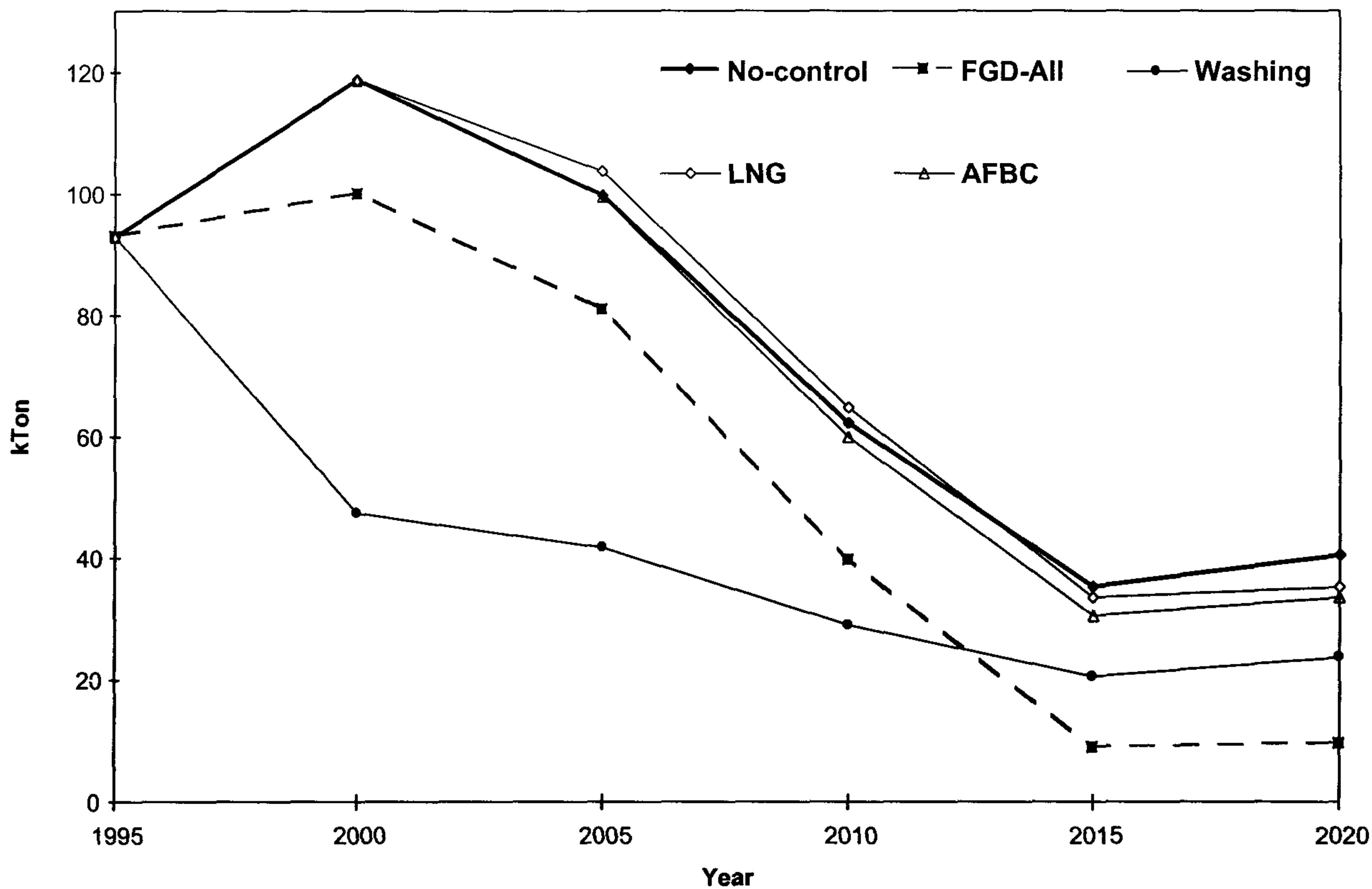


Fig. 3: TSP Emission of Henan Power System

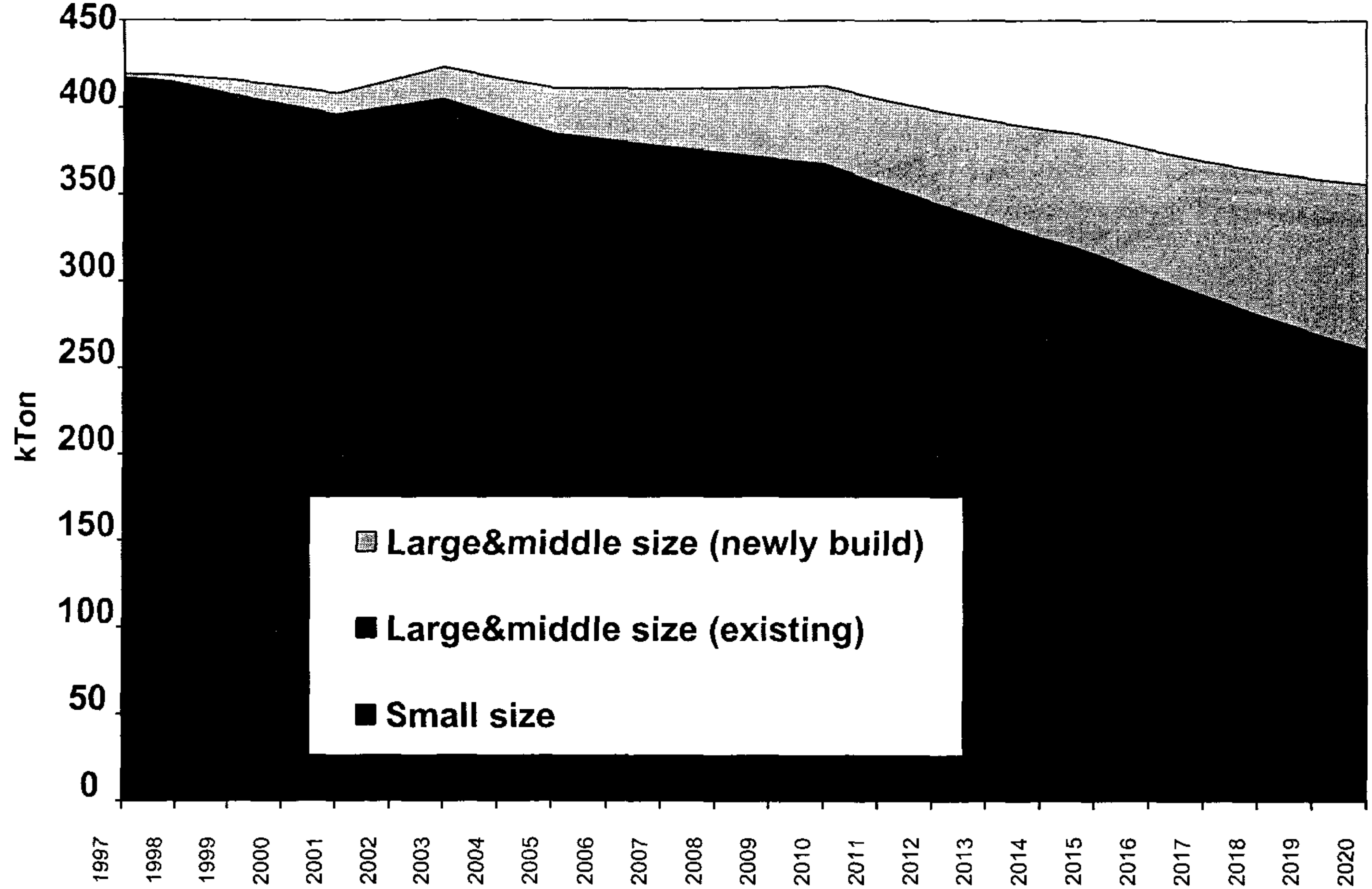


Fig. 4: Cost Effectiveness of TSP Control Options (Henan)

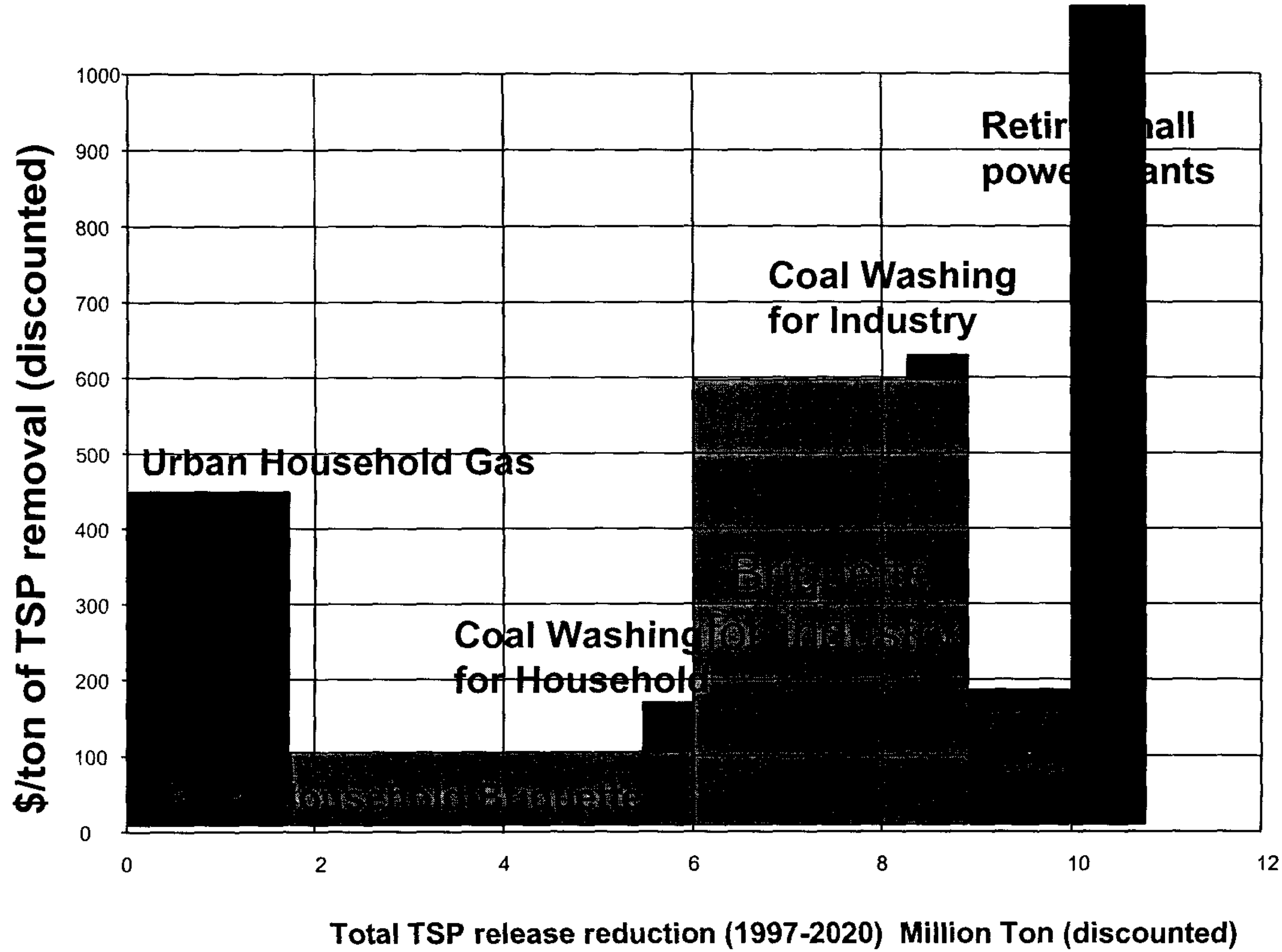


Fig. 5: Cost Effectiveness of TSP Control Options (Shanghai)

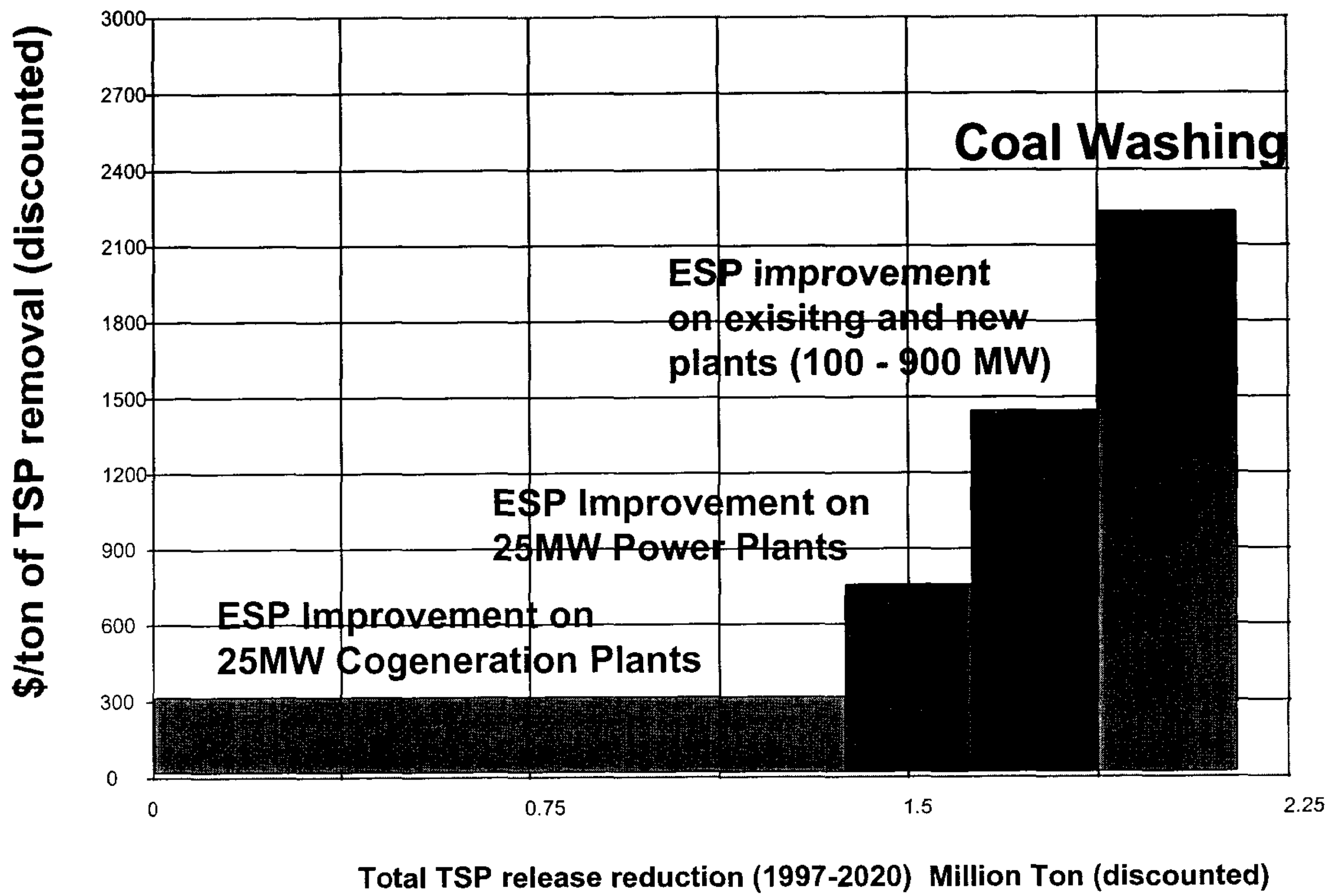


Fig.6: SO_2 emissions in Shanghai, 1997

Total emissions:670,000 ton

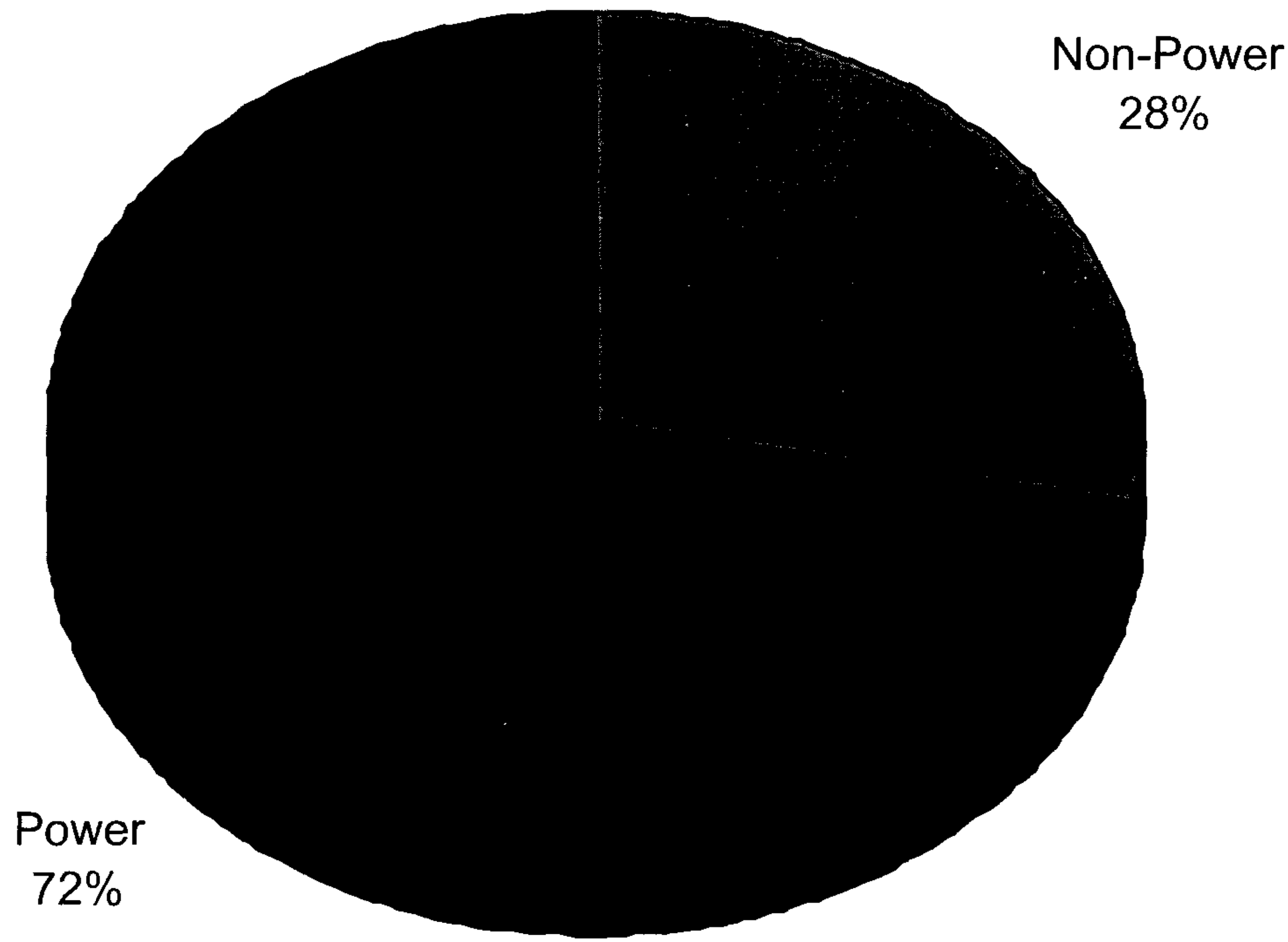


Fig.7: SO2 Emissions in Henan, 1997

Total Emissions: 839,000 ton

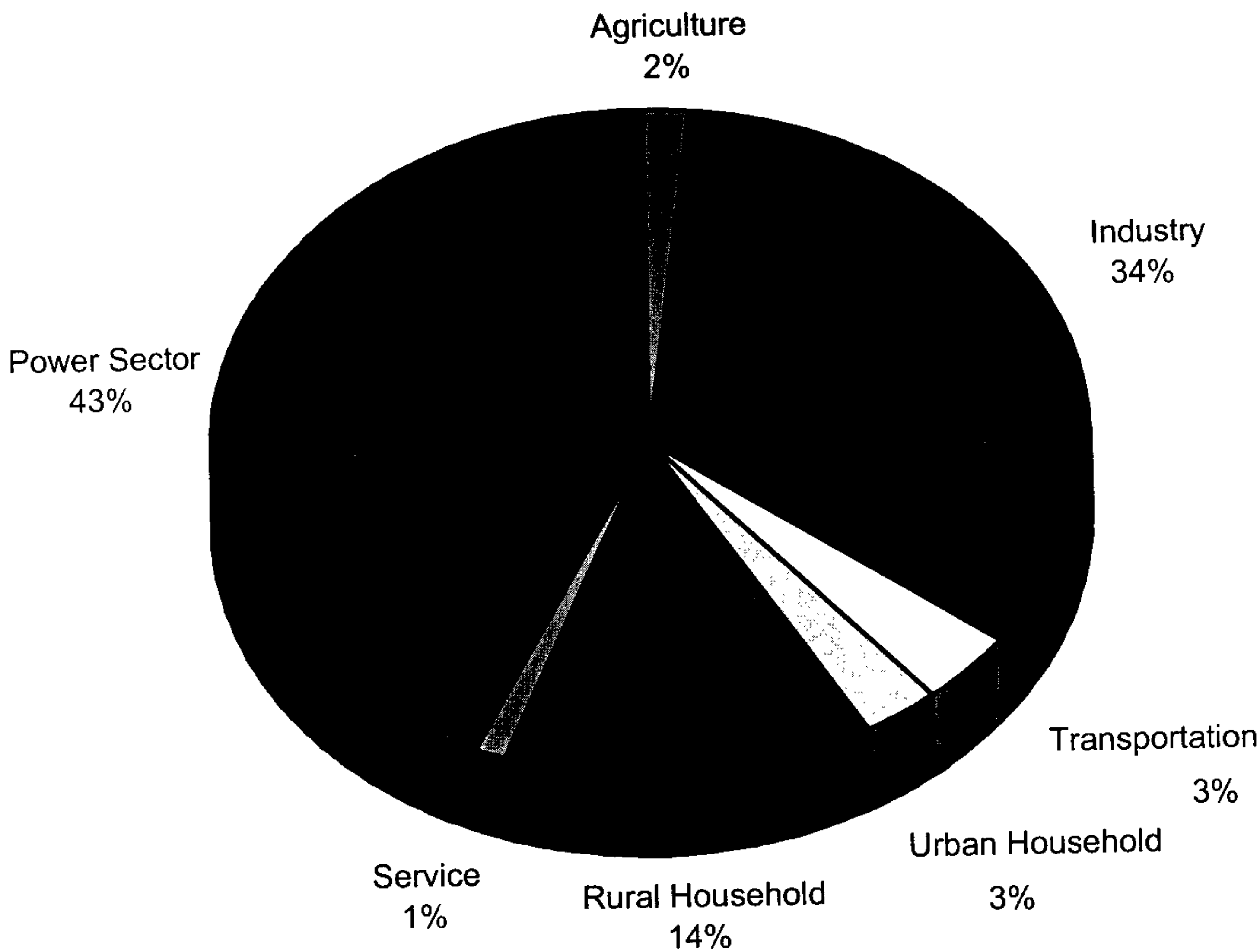


Fig.8: SO2 Emission in Shanghai

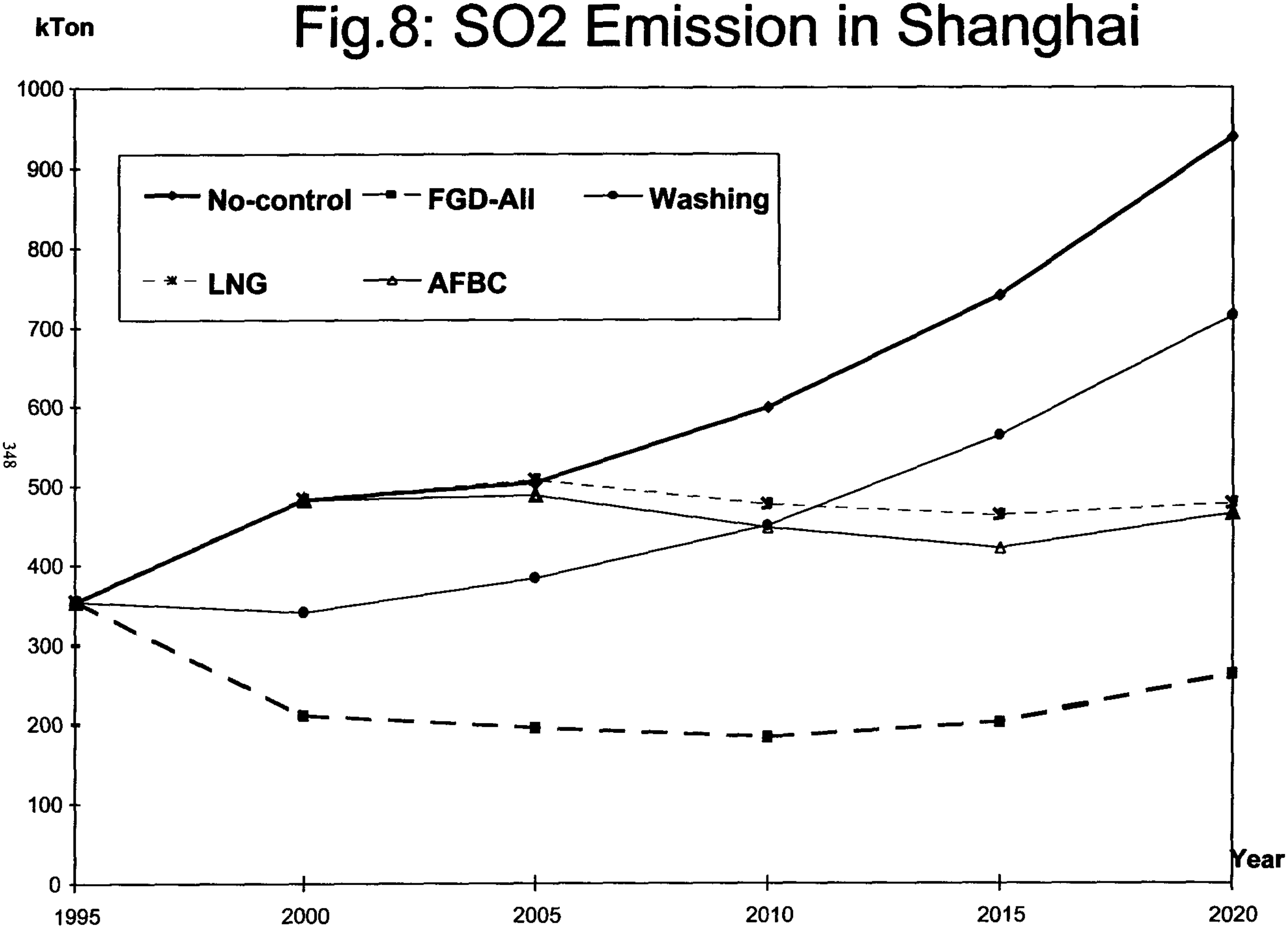
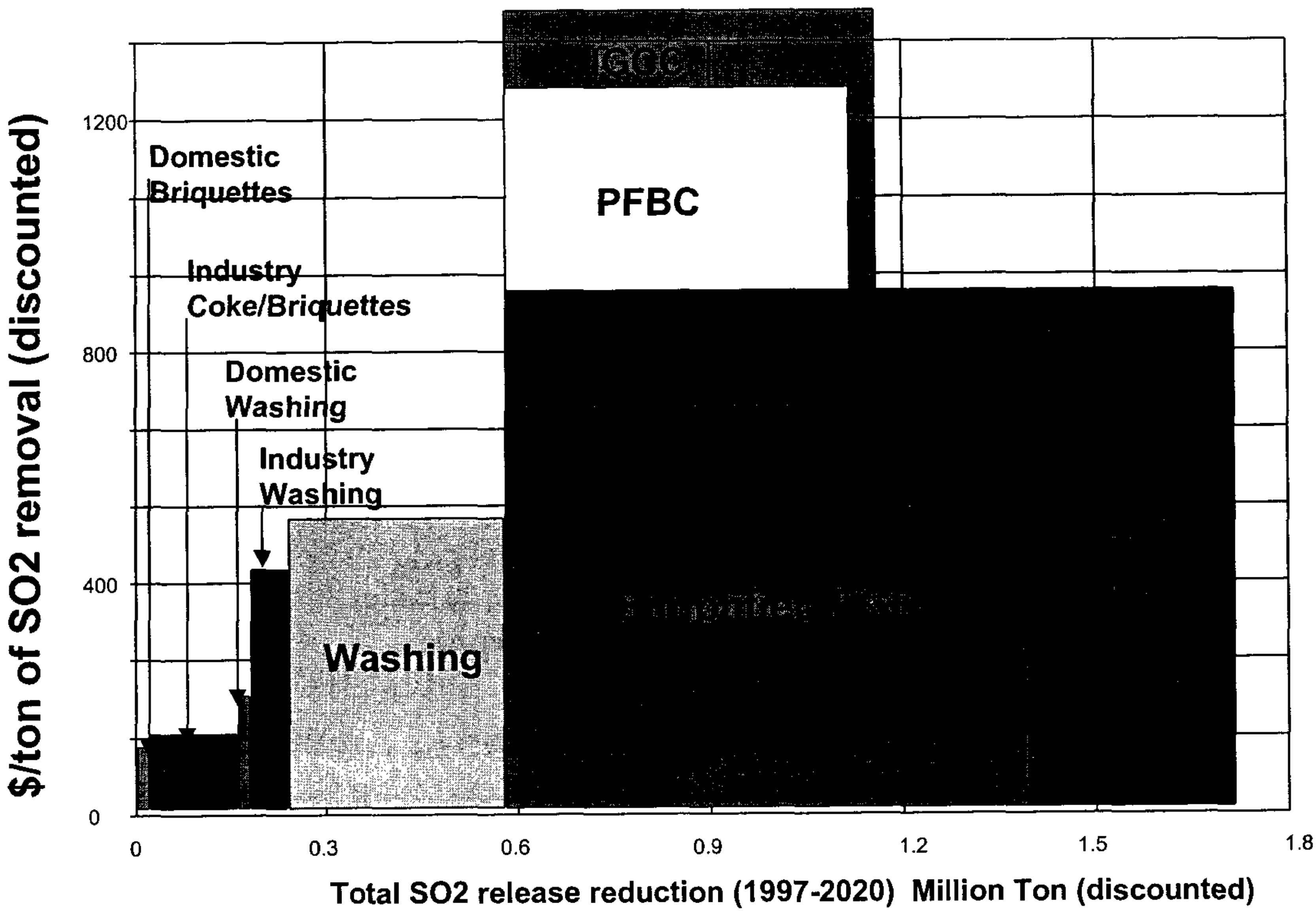
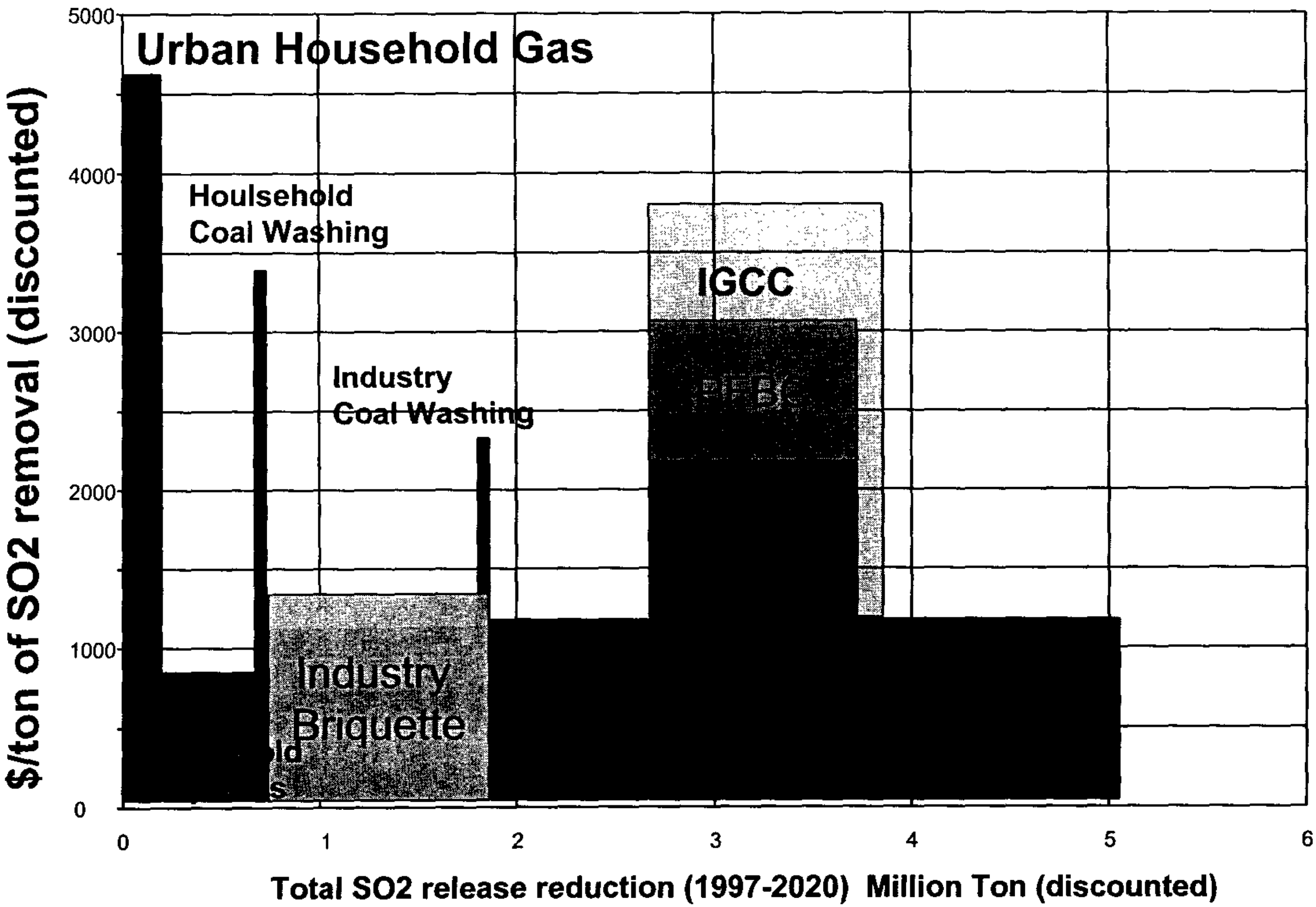


Fig. 9: Cost Effectiveness of SO2 Control Options (Shanghai)



Shanghai study by WB/BERI 1997

Fig. 10: Cost Effectiveness of SO2 Control Options (Henan)



Henan study
by WB/BERI 1998

Fig. 11: NOx emissions in Henan, 1997
Total emissions: 708,000 ton

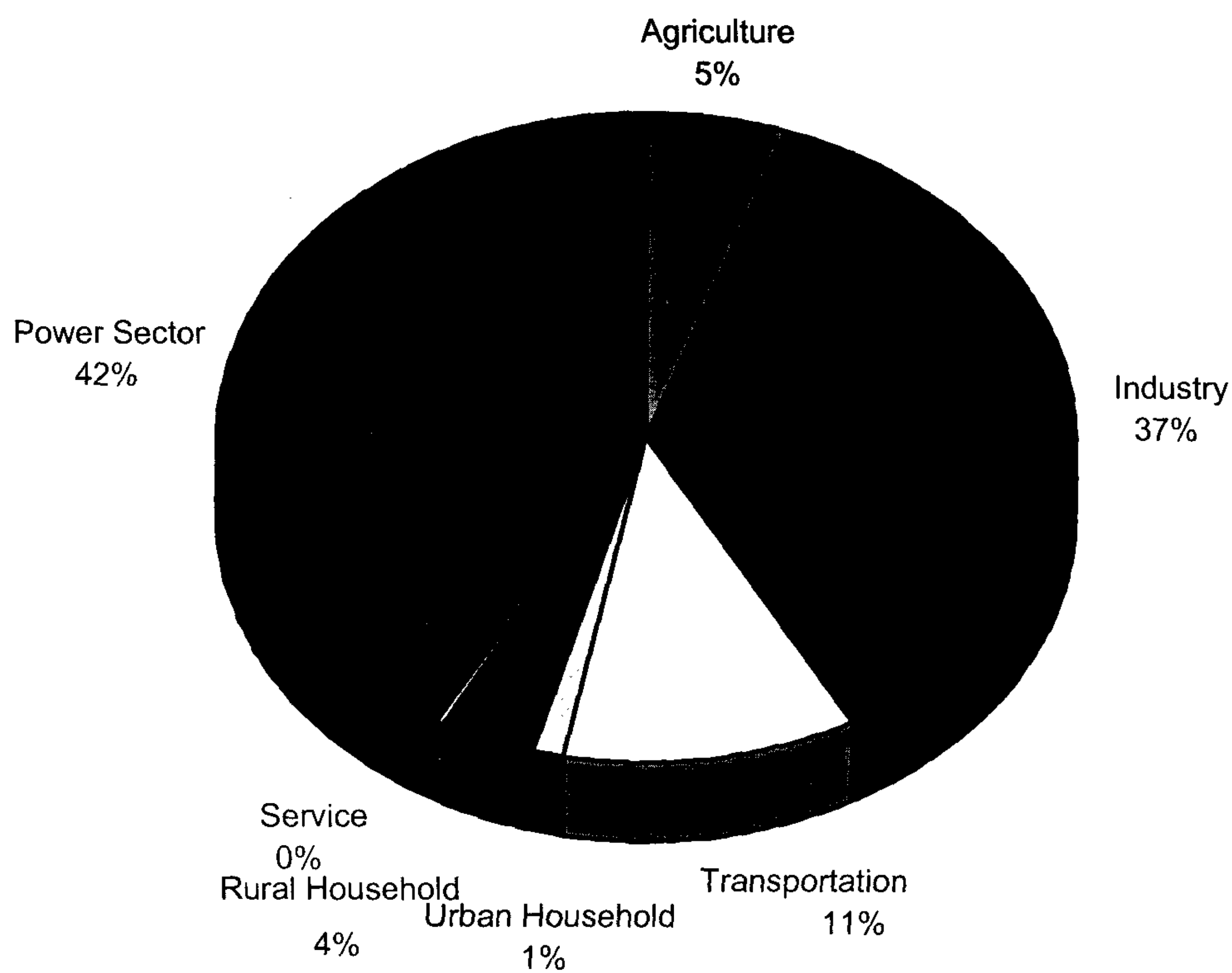
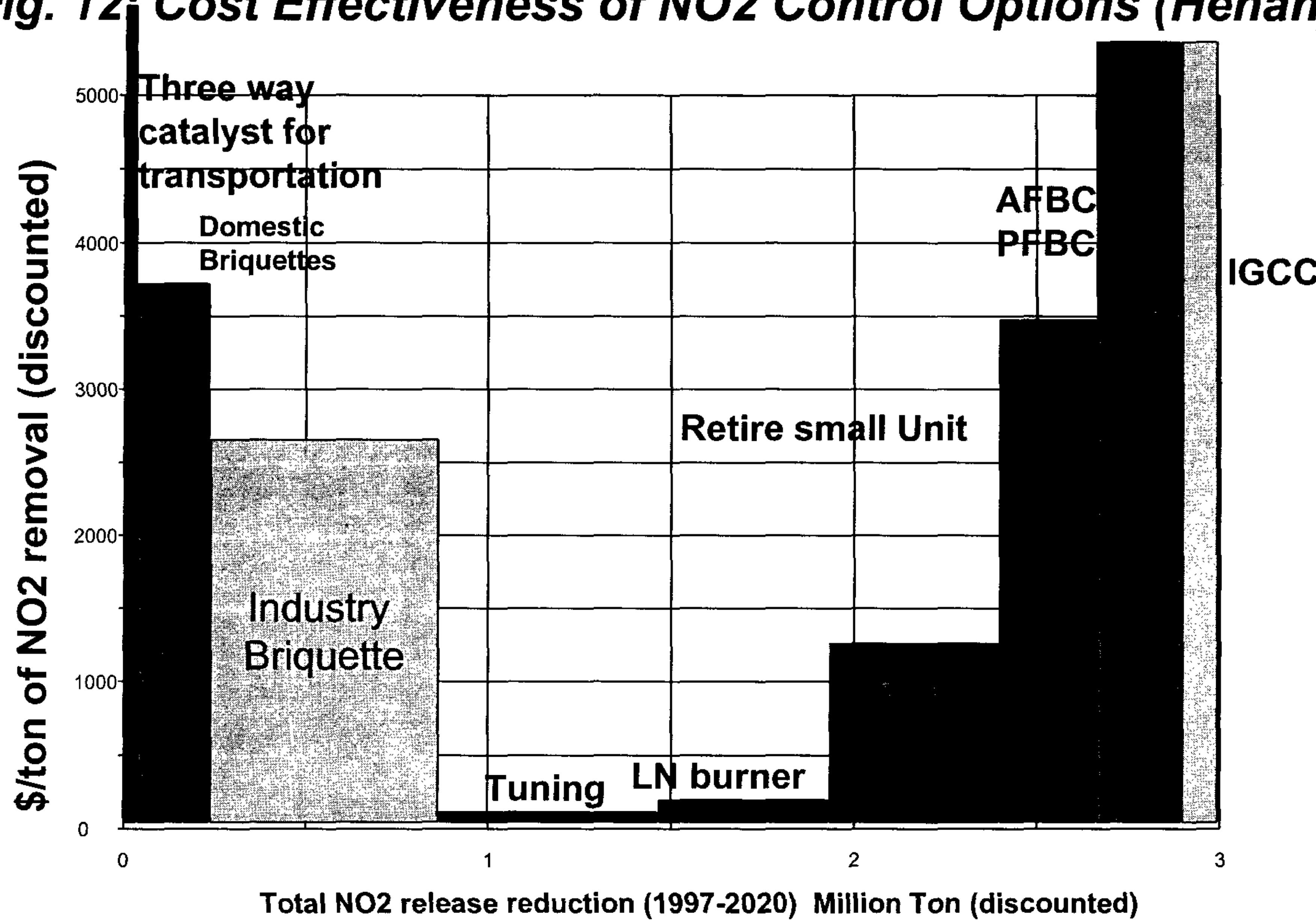


Fig. 12: Cost Effectiveness of NO2 Control Options (Henan)



Henan study
by WB/BERI 1998

Fig. 13: **TSP Emission of Henan Power System (with TSP limitation)**

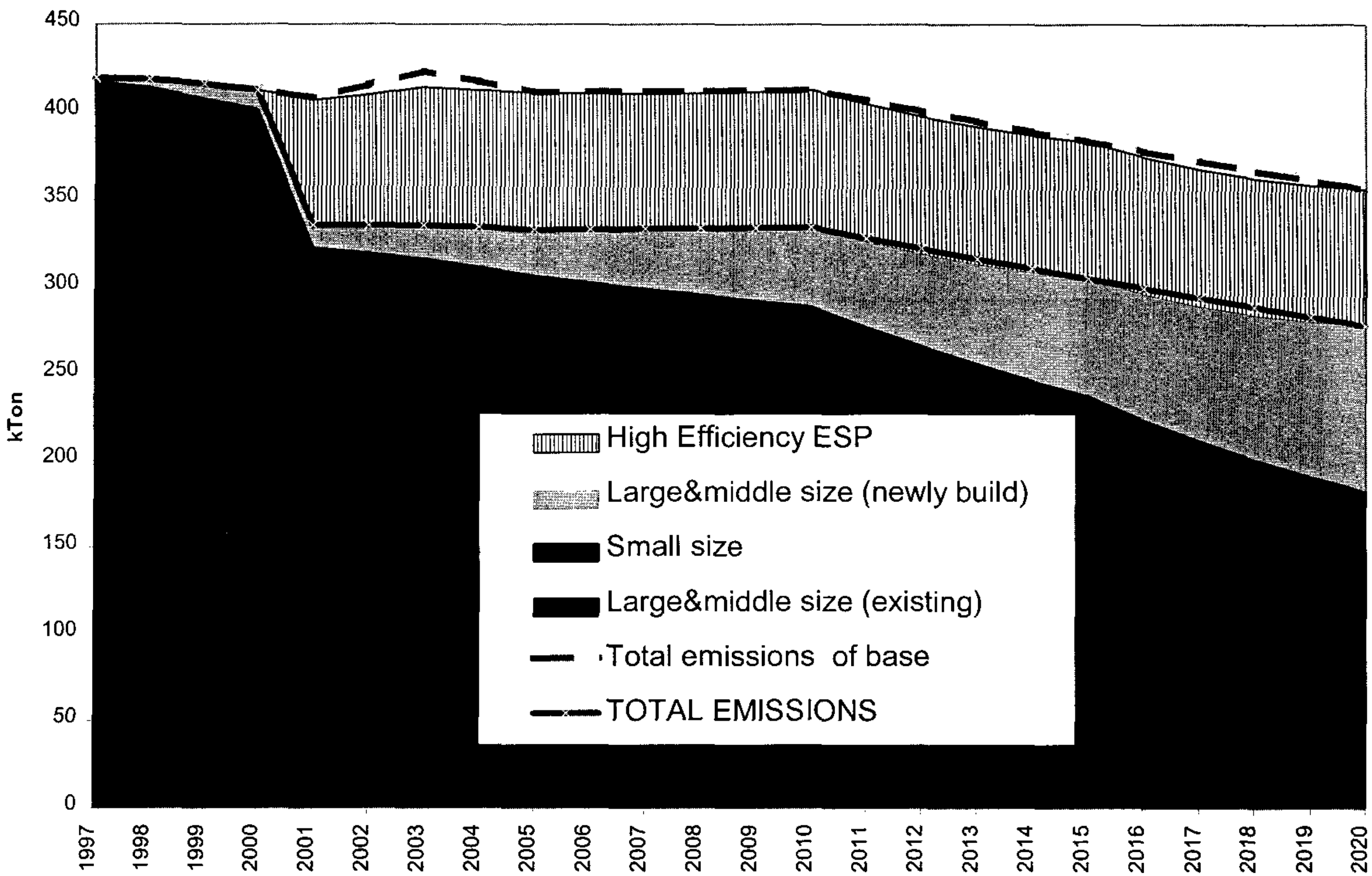


Fig. 14: SO2 Emission of Henan Power System (with SO2 limitation)

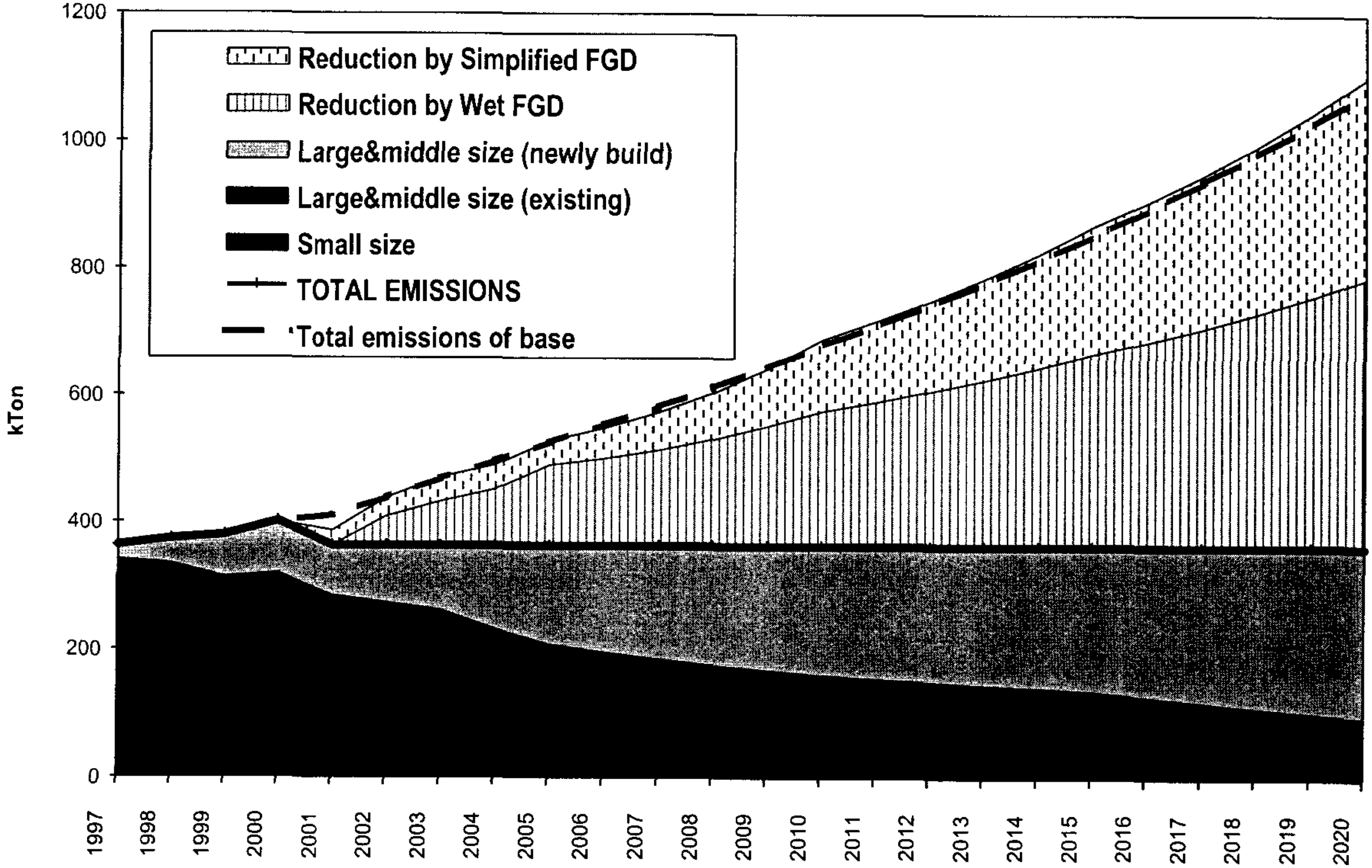


Fig. 15: NOX Emission of Henan Power System (with NOX limitation)

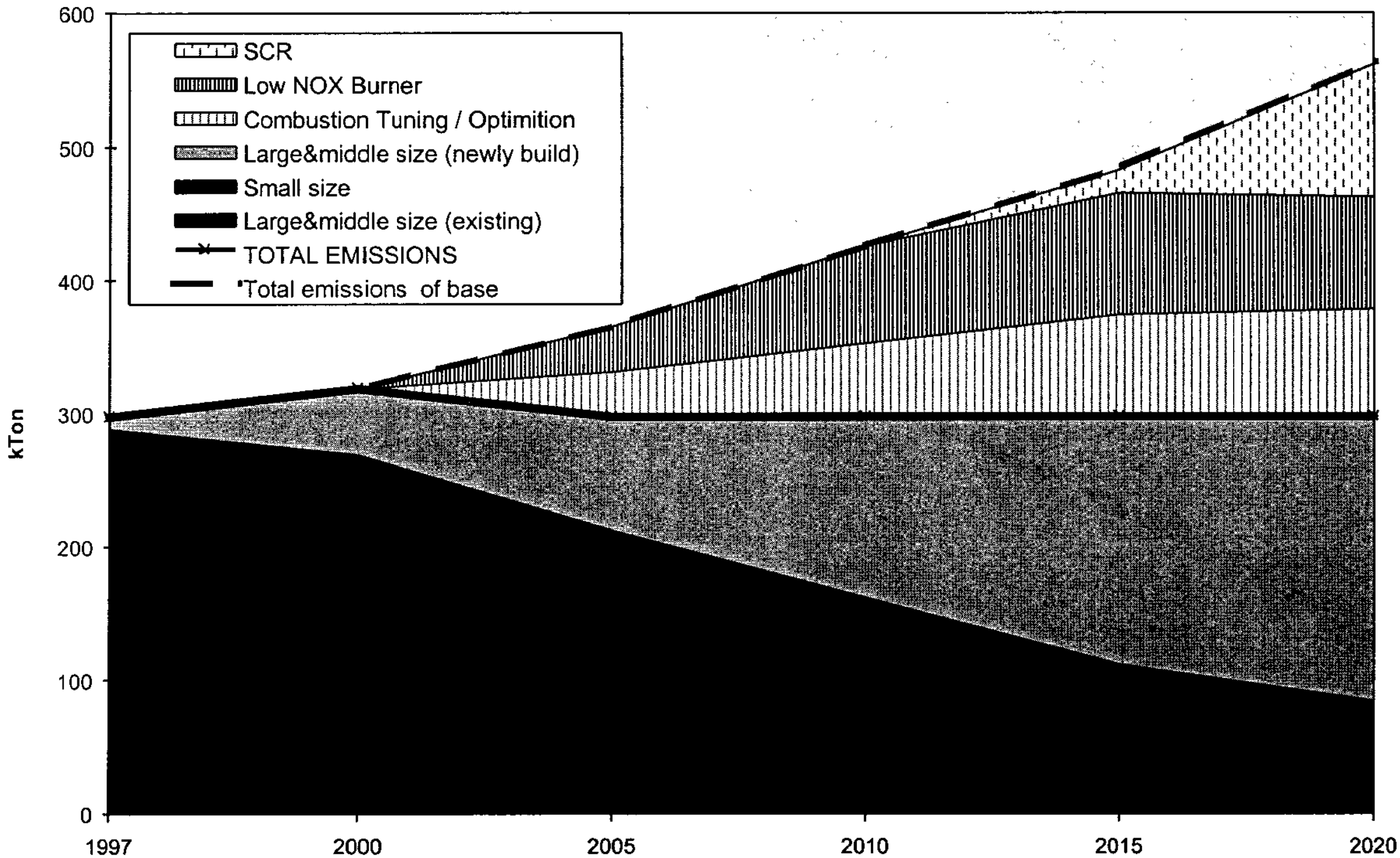


Fig. 16: Electricity Generation Mix

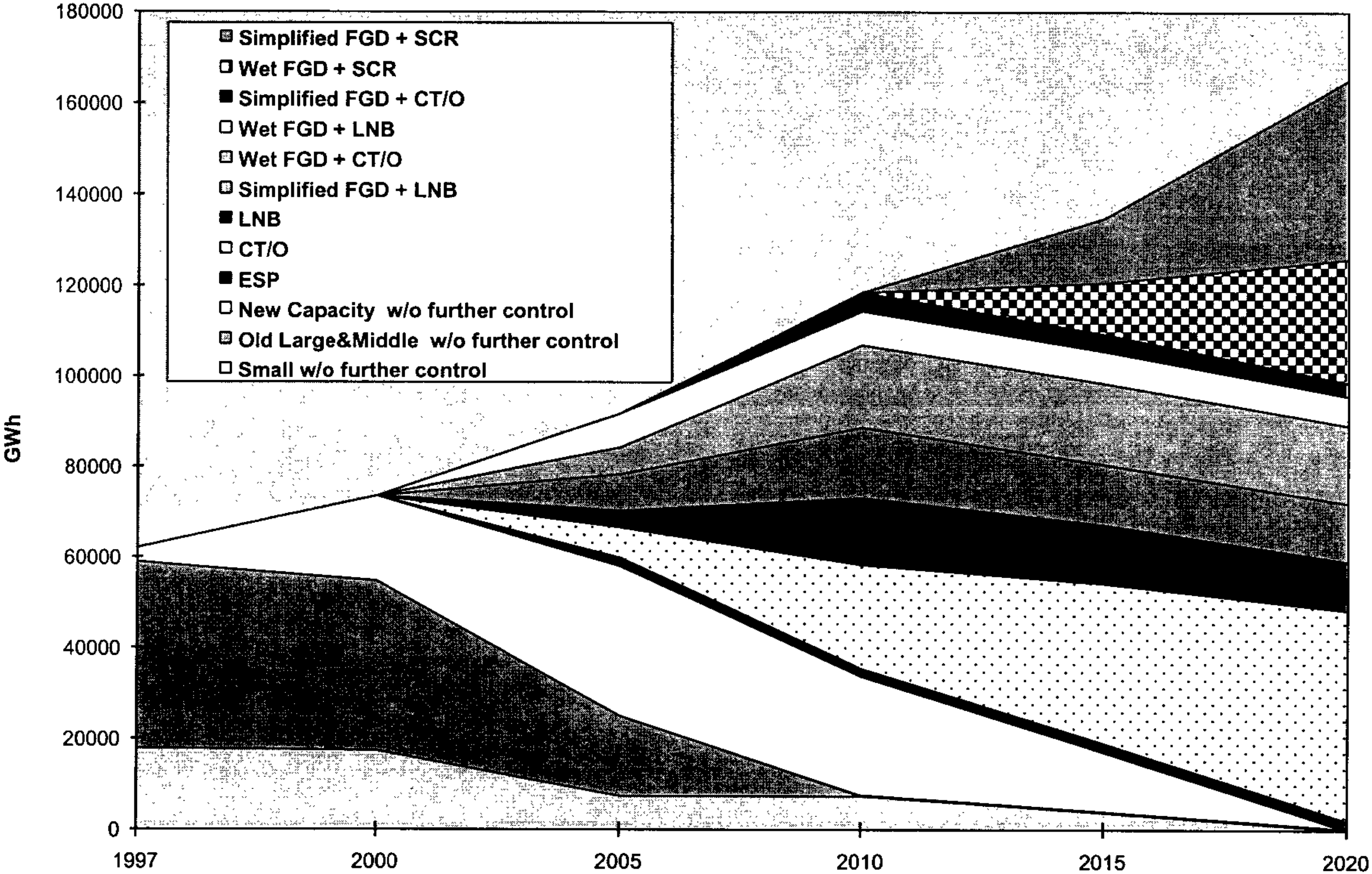


Fig. 17: **TSP emission of power system (with all limitations as of 1997 level)**

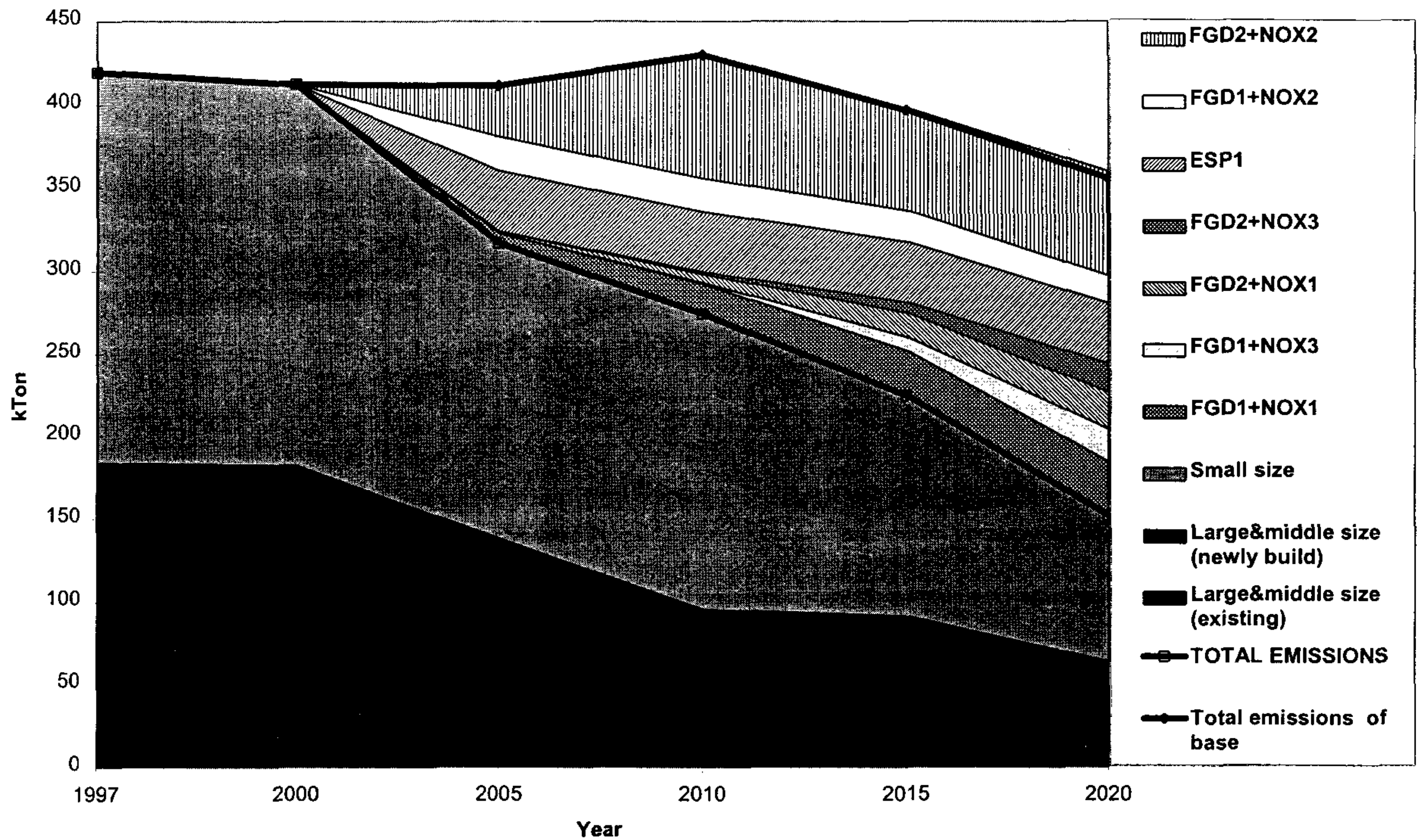


Fig. 18: **SO2 emission of power system (with all limitations as 1997 level)**

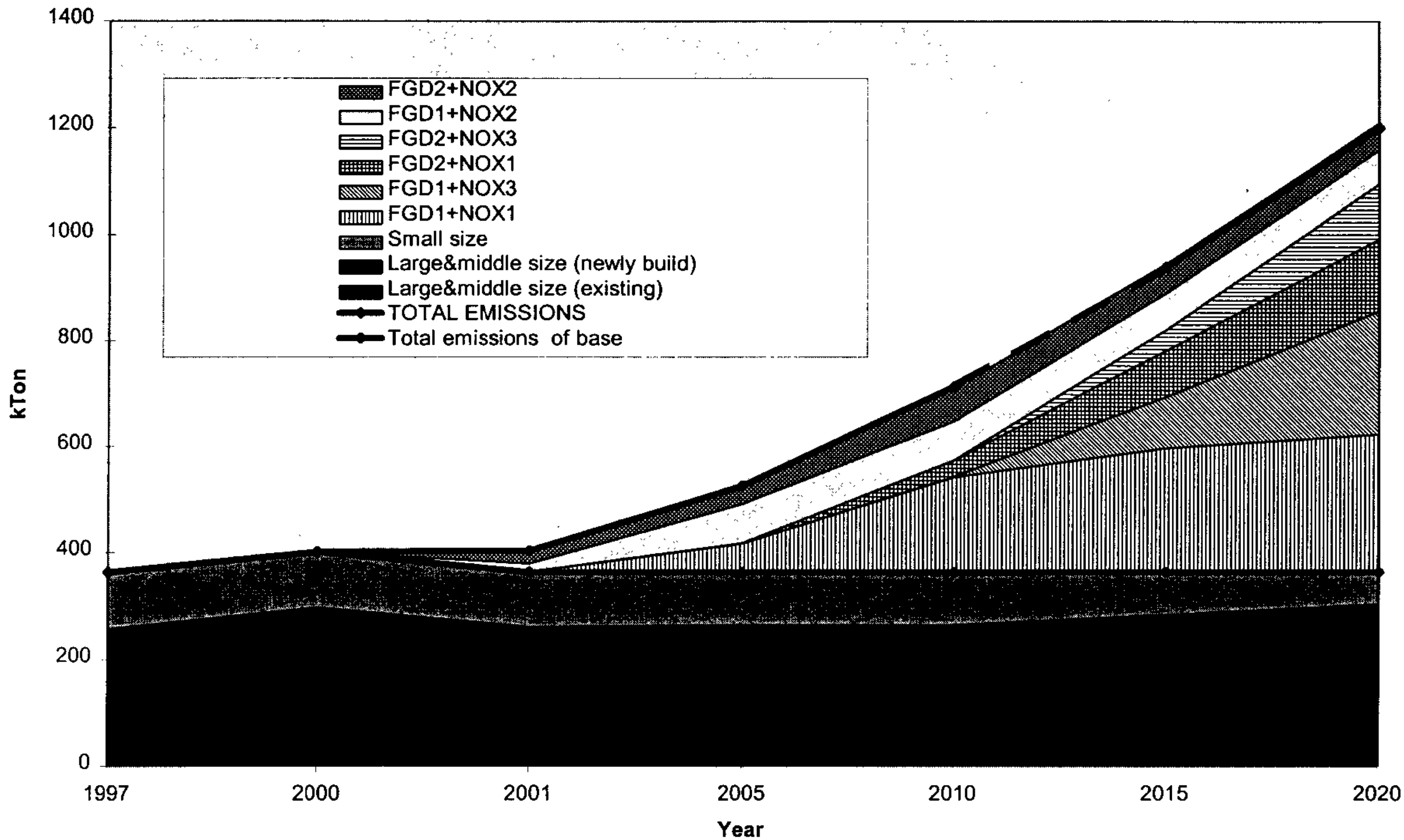


Fig. 19: **NOx emission of power system (with all limitations as of 1997 level)**

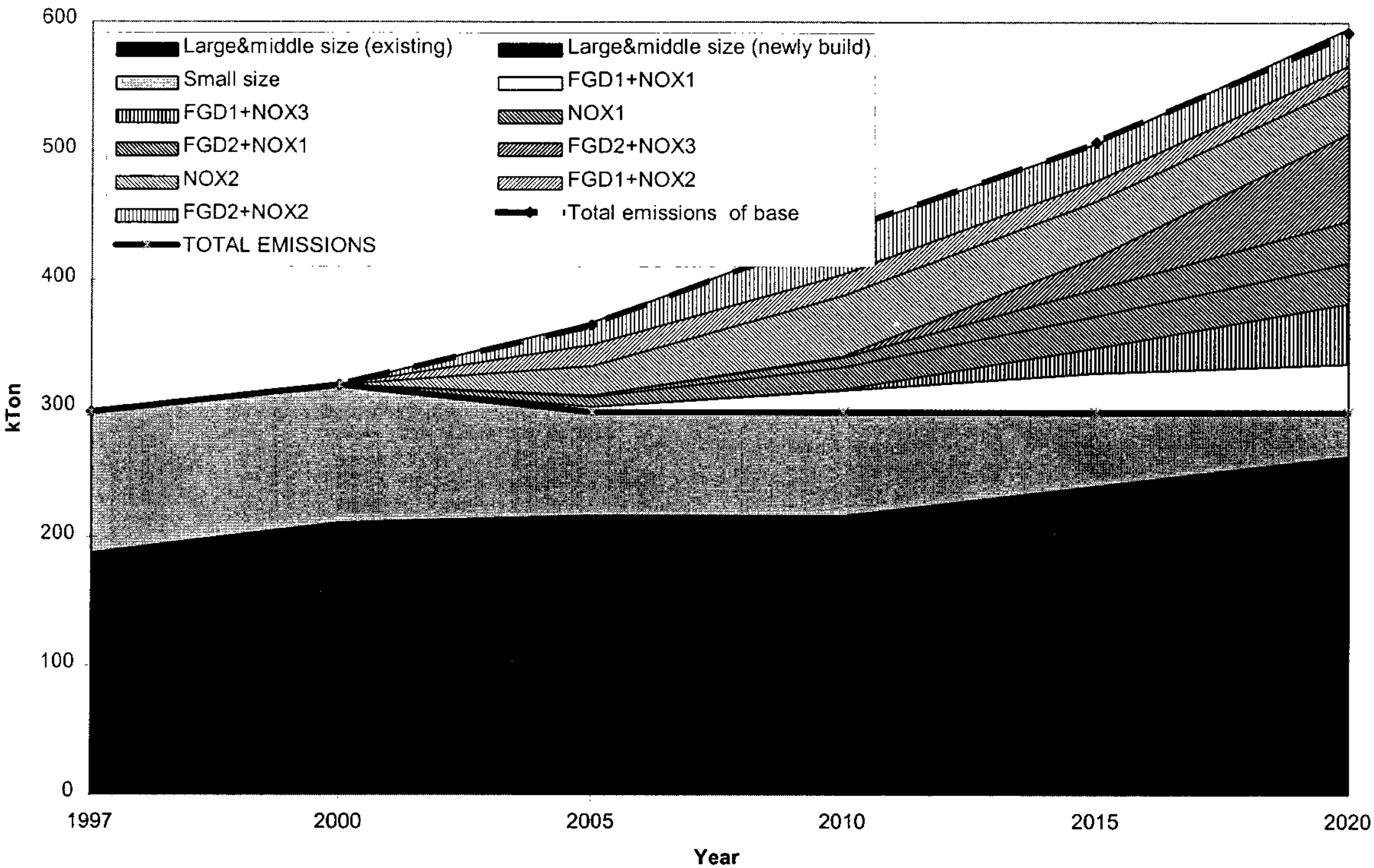


Fig. 20: Present value of System Cost of each Cases in Henan Power Sector

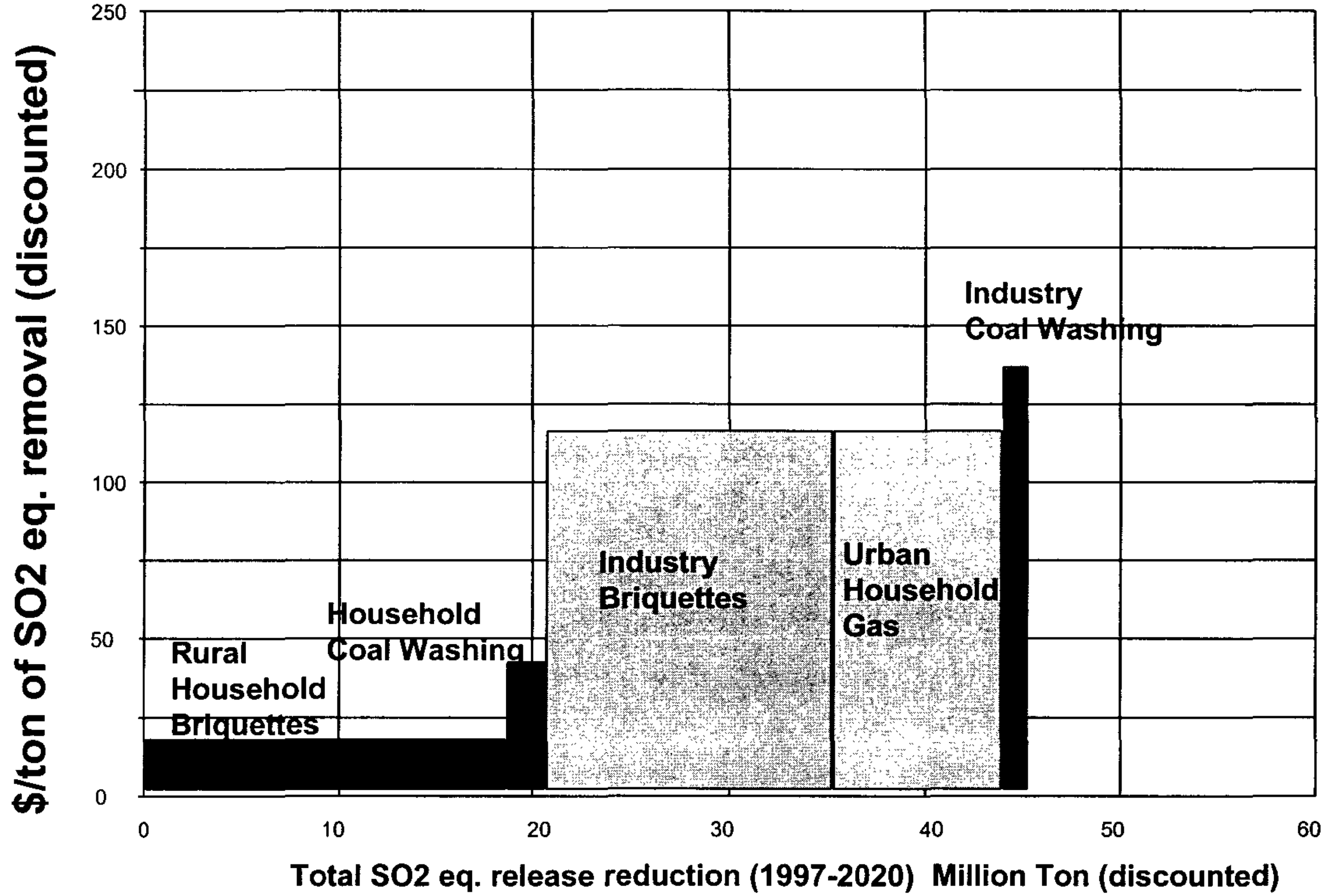
Million Yuan	Total Cost	Investment Cost	Fuel Cost	O&M Cost	EM-control Cost	AIC Yuan/kWh
BASE CASE	159360.0	63769.1	67412.8	28178.2	0	0.262
SO2 limitation	165745.8	64404.2	67709.8	29331.6	4300.2	0.289
NOx limitation	160154.4	63794.7	67403.3	28232.8	217.0	0.265
TSP limitation	159647.8	63803.9	67404.3	28215.8	730.5	0.264
All limitation	166581.9	64427.7	67682.6	29211.2	5260.5	0.294
Further limitation	171195.9	64716.3	67832.6	29895.1	8752.1	0.318

Fig. 21: Externality per weight of pollutant in Shanghai and Heanan

	$ 1996/ton	Shanghai		
	Local	Regional	Distant	Total
TSP/PM10	569	807	527	1902
SO2	137	120	133	389
NOx	159	141	154	455

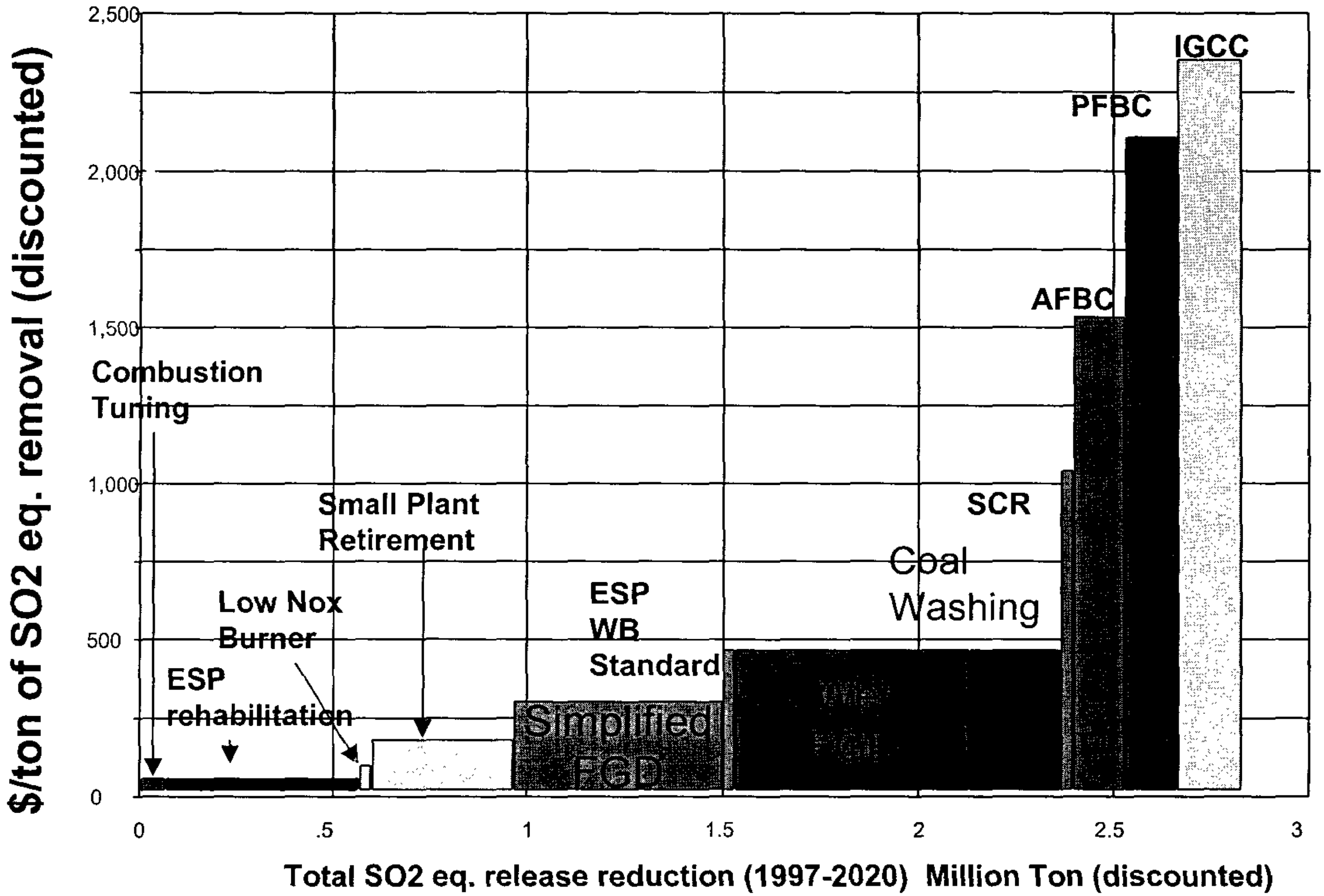
	$ 1996/ton	Henan		
	Local	Regional	Distant	Total
TSP/PM10	25	182	733	940
SO2	6	27	183	217
NOx	7	32	214	252

Fig. 22: Cost Effectiveness of Pollutant Control Options for Non-Power Sector (Henan)



Henan study by WB/BERI 1998

Fig. 23: Cost Effectiveness of Pollutant Control Options for Power Sector (Henan)



Henan study by WB/BERI 1998

Fig. 24: Externality in Henan

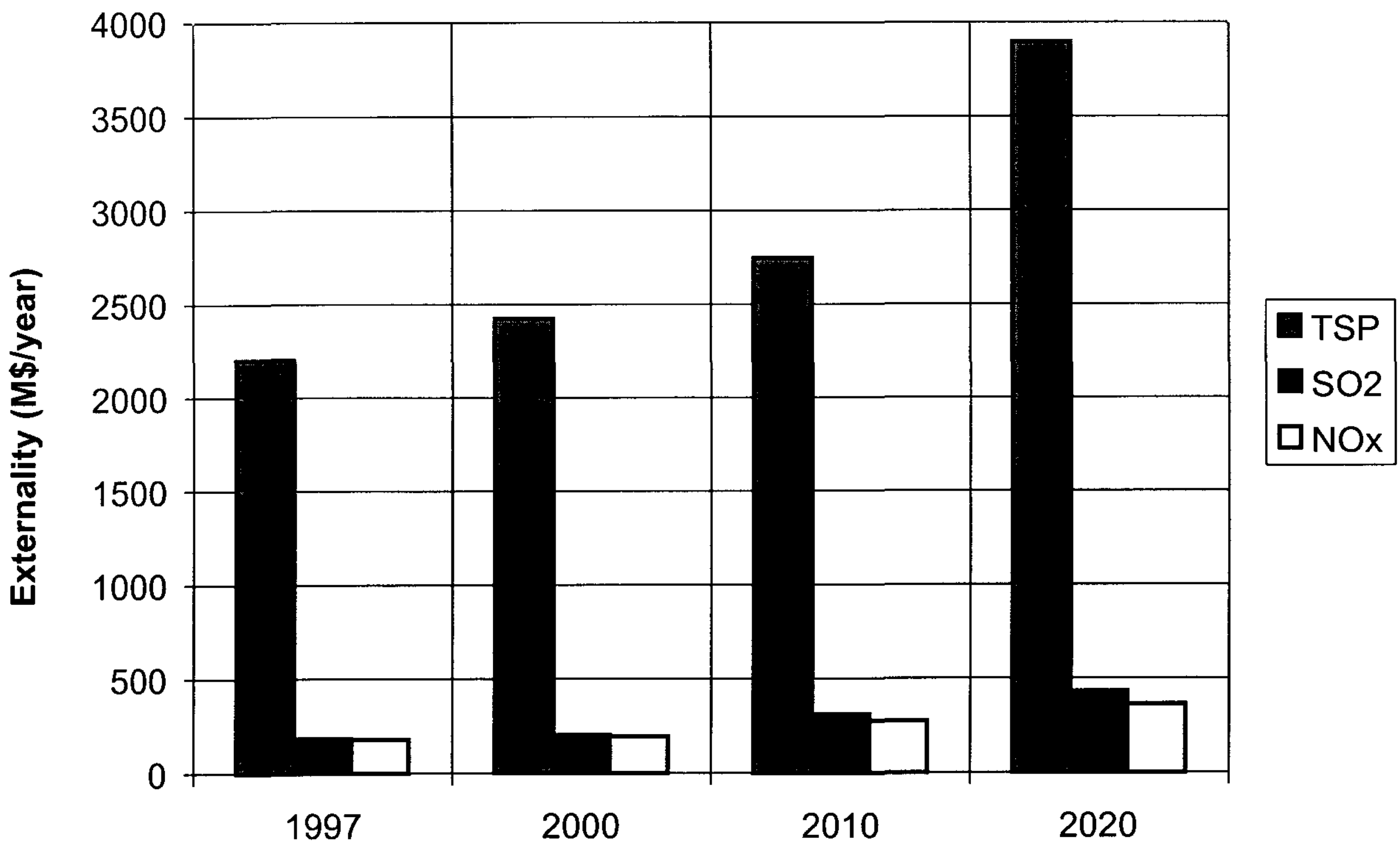


Fig. 25: Externality by Power Sector in Henan

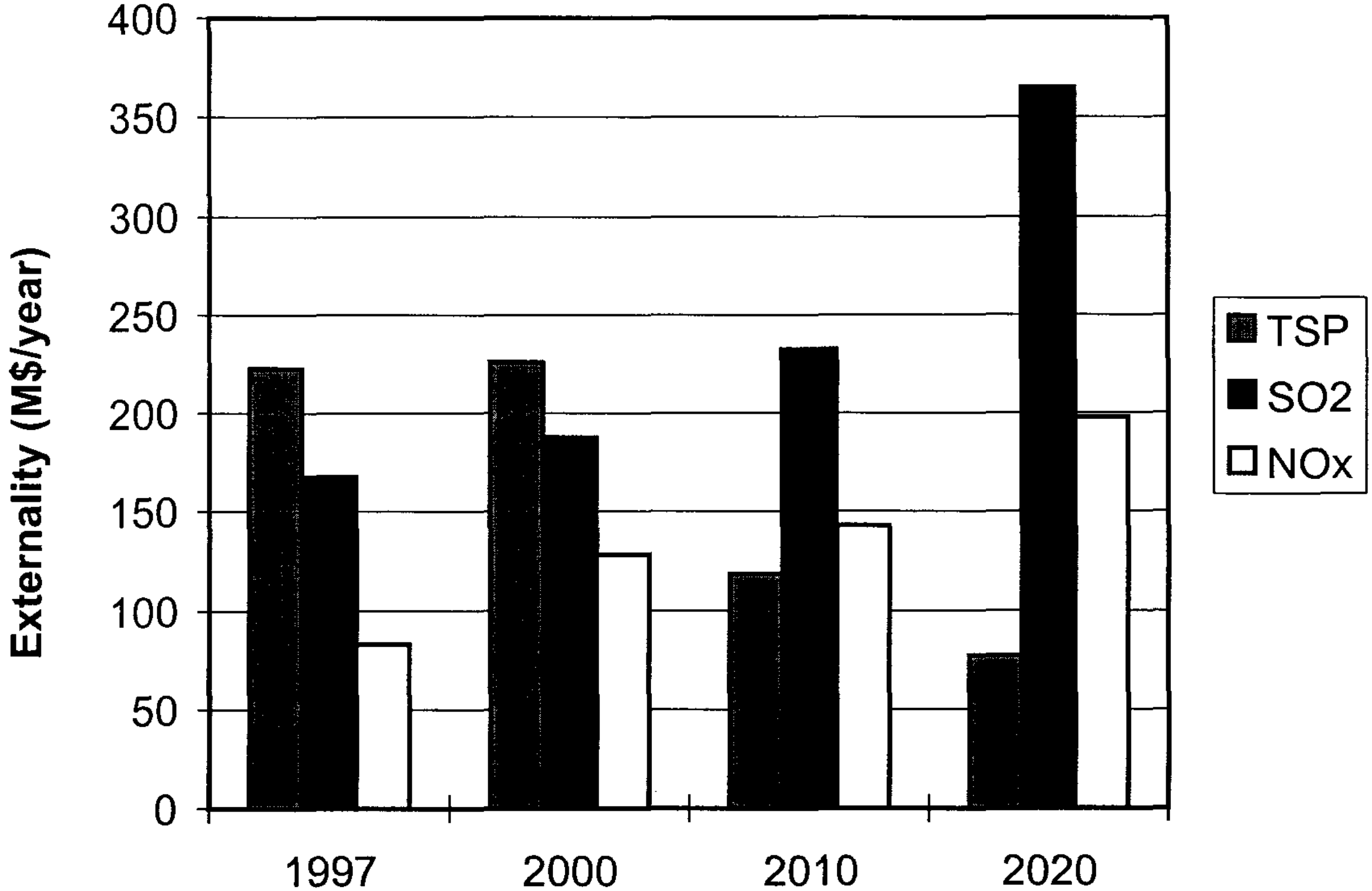
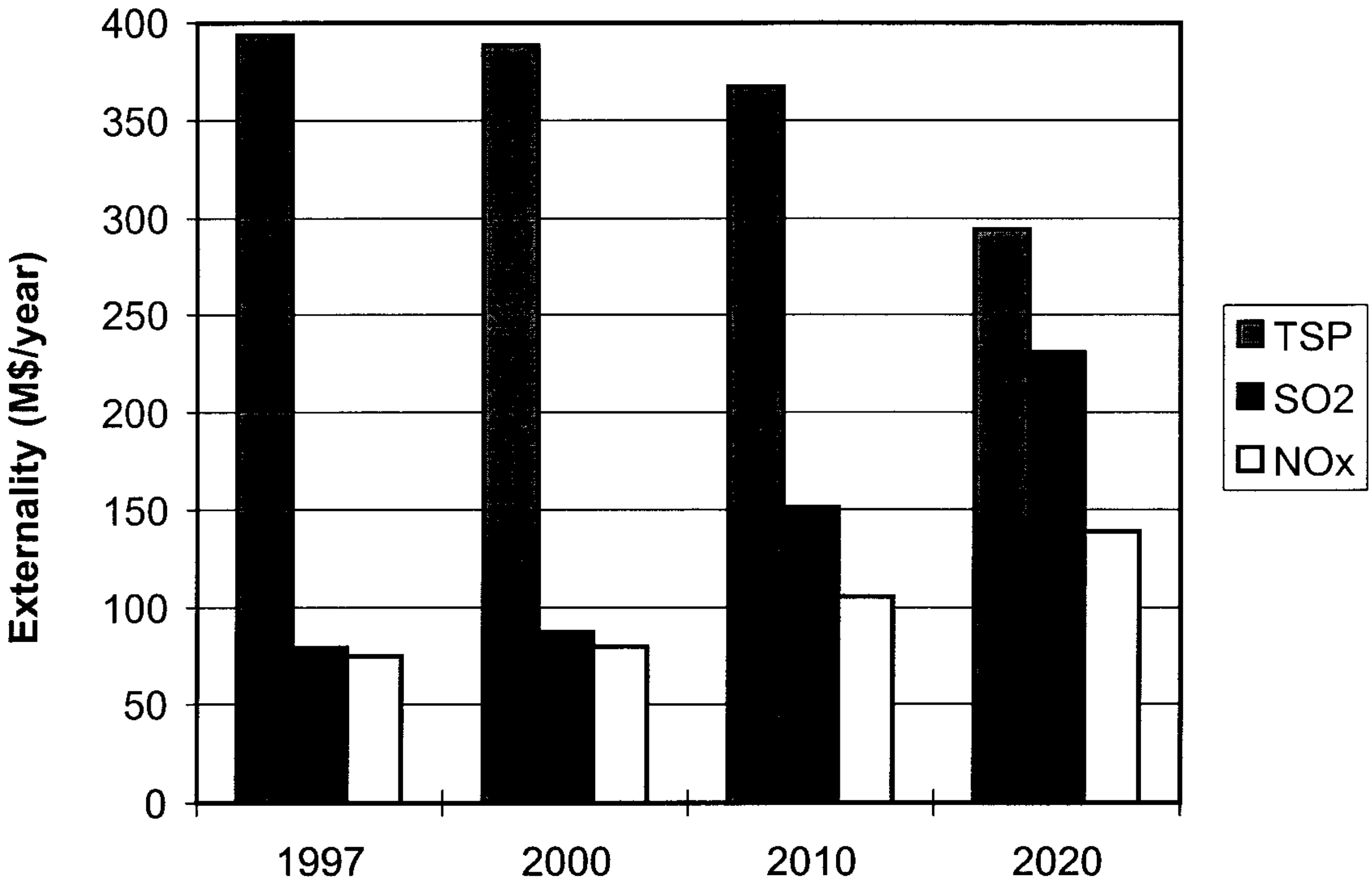


Fig. 26: Externality by Power Sector in Shanghai

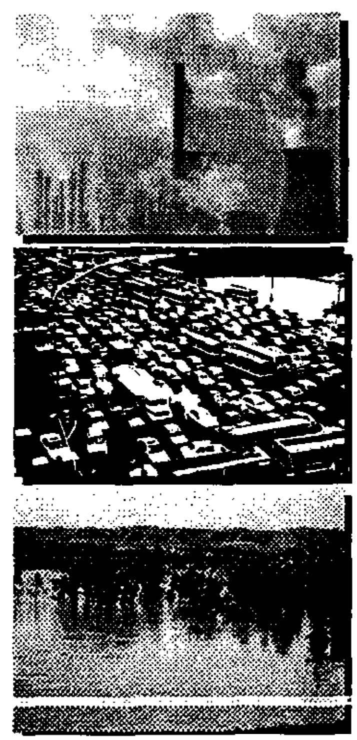


Climate Change and Clean Coal: An Emerging International Business Opportunity

THE WORLD BANK

"Continued global warming is in nobody's interest, but the simple facts of the matter are that developing countries will suffer the most damage, and their poor will be at an even greater disadvantage. I see the Bank's role in climate change as providing every opportunity to developing countries to benefit from the huge investment OECD must make in reducing climate change"

James Wolfensohn
UNGASS
June 1997



World Bank and Climate Change

- World Bank believes in the science of climate change
  - subscribe to assessments of the IPCC
- Our clients are vulnerable
  - OECD damages = 1-3% of GDP
  - LDC damages = 5-9% of GDP
- The time for action is now
  - precautionary principle applies
  - long lead-times for technological change

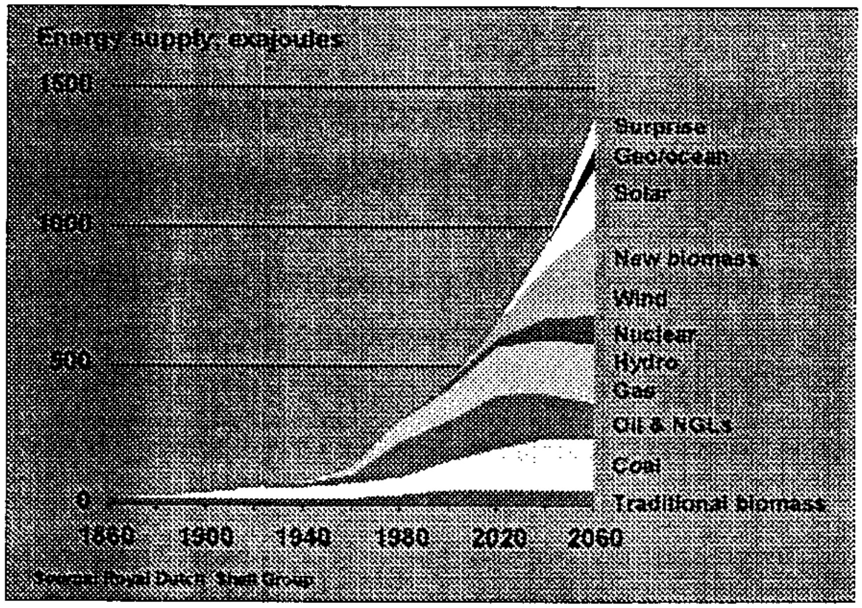
The Opportunity

- Domestic picture may be "gloom and doom"

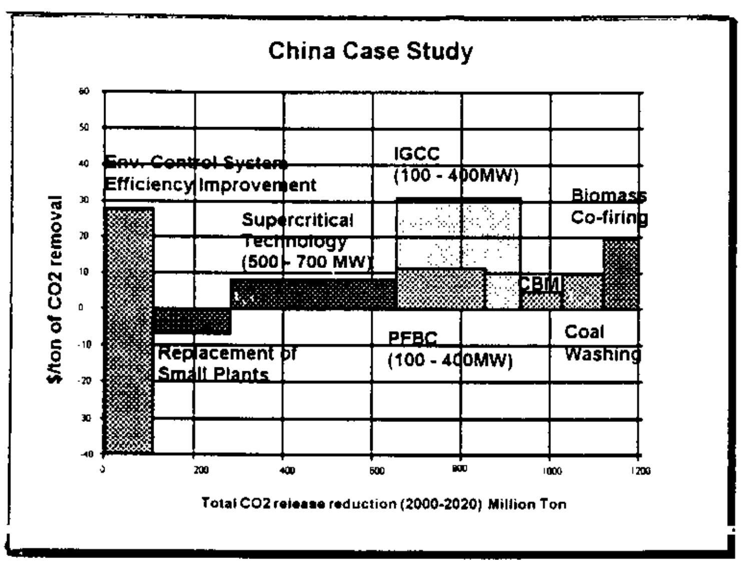
But:

- OECD-led efforts to combat climate change are creating new international business opportunities for clean coal technologies that offer CO2 benefits

The Energy Transition

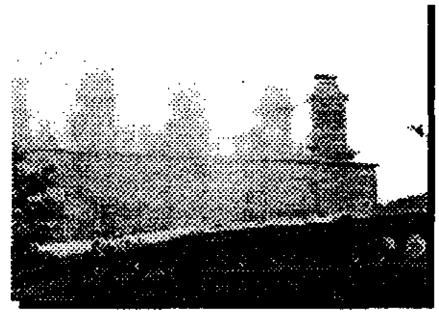


Cost Effectiveness of CO2 Control Options in the Coal Sector



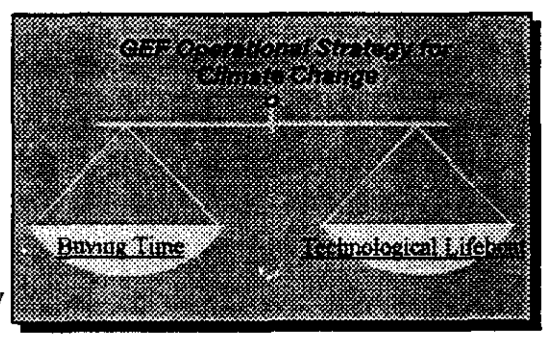
IBRD Financing
China - Waigaoqiao Thermal Power

- Typical Chinese coal-fired power plant efficiencies:
  - <50 MW plants = 25%
  - system average = 29%
- New 2 x 950 MW IBRD-financed coal power plant:
  - supercritical steam cycle
  - efficiency = 40.5%
  - low/no-cost GHG control



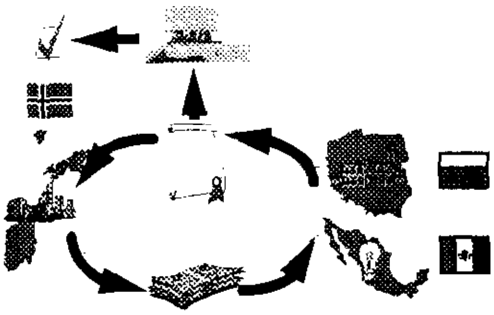
Global Environment Facility
Climate Change Investments

- Program GEF climate change investment resources as per the agreed GEF Operational Strategy

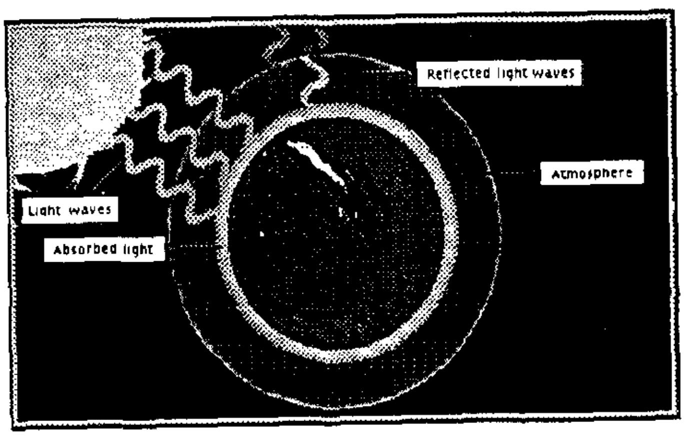


Carbon Offset Financing under the Kyoto Protocol

- Promote an efficient and equitable carbon offsets market through creation of new financial instruments



GEF Operational Strategy for Climate Change



Partners in GEF Implementation

- UNDP: technical assistance
- UNEP: scientific and technical advice
- World Bank: investment operations; funds administration

GEF Financing Modalities

- To eligible *developing countries* (FCCC ratifier; WB/UNDP recipient)
- Provides *incremental cost financing* (i.e., portion not justified in the domestic context) to obtain global benefits
- In response to *government requests* or may grant direct to *private sector* with government approval

GEF Financial Resources

$2.8 billion

Resource Allocation Strategy

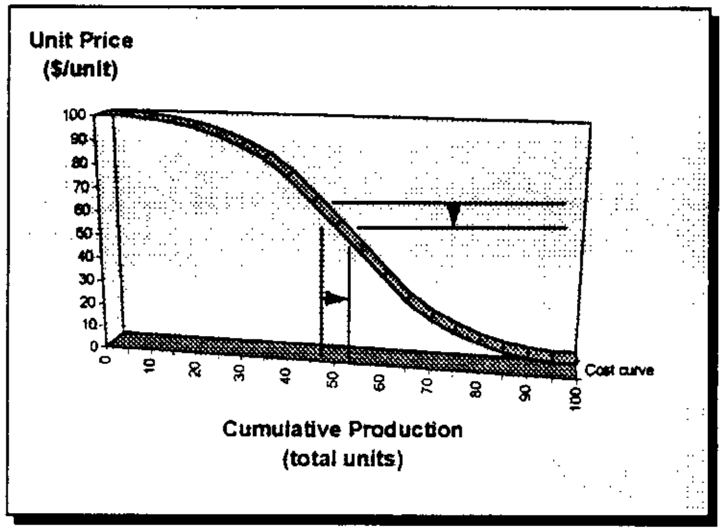
"<u>Buying Time</u>"

- < $10/tonne Carbon
- Technologies:
  - Fuel switching
  - Methane leakage/flaring
  - Adv. electricity generation cycles
  - Carbon sequestration & biomass production

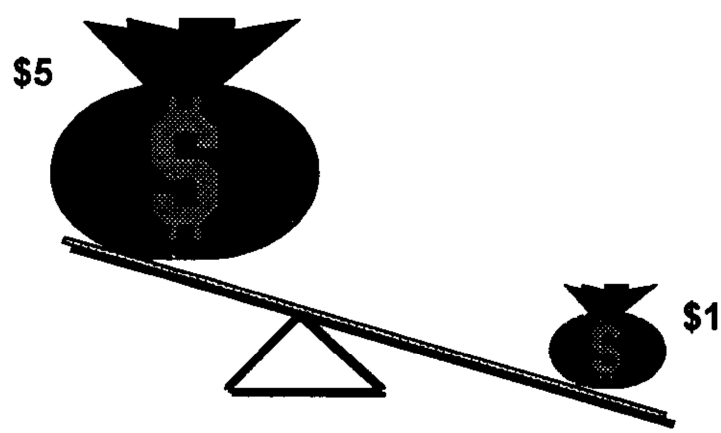
"<u>Technological Lifeboat</u>"

- Low or no carbon & high present cost, but steep learning curves
- Technologies:
  - PV
  - Solar thermal-electric
  - Wind
  - Coal + biomass gasification
  - Fuel cells

Learning Curve Effects



Leverage



India - Coal IGCC Projects

- Typical Indian coal-fired power plant efficiencies:
  - new plants = 34%
  - system average =29%
- 100 MW IGCC plant:
  - 42% efficiency = 20% CO_2 savings
  - simultaneous control of NOx, SOx and PMT
- Projects under study:
  - NTPC (IBRD/GEF)
  - AEC (IFC/GEF)

The Global Carbon Initiative

The World Bank Group

Example of Bilateral Trade: Norway and India

- Domestic abatement option:
  - upgrade already efficient gas-fired plant at abatement cost of $60/tonne
- International abatement option:
  - invest in technology switch at low-efficiency Indian coal power plant
  - abatement costs are low at $20/tonne because of large coal use efficiency gain
- Surplus to be shared: $60 - $20

Market Needs and the WBG's Role

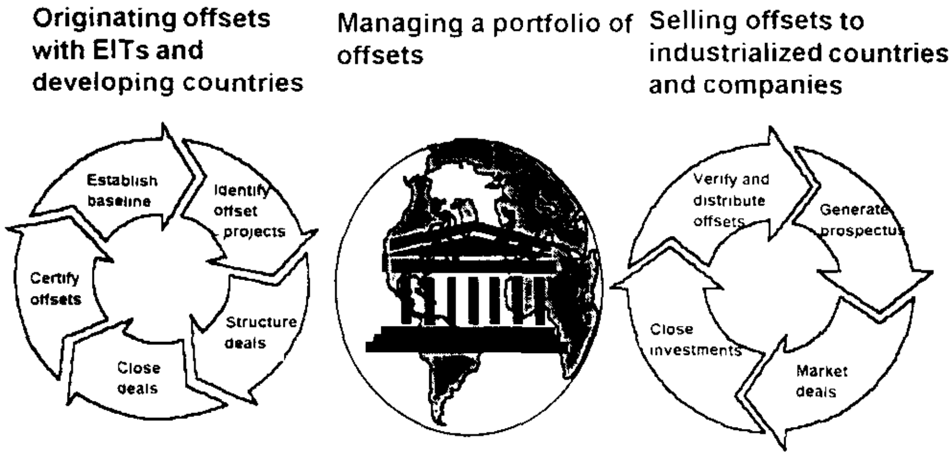
Buyers of carbon offsets need:	Suppliers of carbon offsets need:
• Good investment opportunities • Certification of offsets	• Share of surplus • Access to technology

WBG will be a broker in deals for carbon investment by providing two products:

1) Project-based Investments (bilateral)

2) Prototype Carbon Fund

Prototype Carbon Fund



- Consistent portfolio strategy
- Well- diversified risks
- Low transaction costs
- Efficient administration

Potential Market Scenarios

(Volume transactions in 1996 US$ billions)

	2000	2005	2020
High *Global Coverage* Strong commitments	1	16	60
Middle Extensive Geographic Coverage Moderate commitments	1	8	30
Low Central and Eastern European Countries; Weak commitments	1	3	10

STAP/GEF Report

Prospects for Reducing GHG Emissions in Coal Systems

Prepared by
The Scientific and Technical Advisory Panel of the Global Environment Facility

29 September 1997

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PREFACE

It is a pleasure to present the report *Prospects for Reducing GHG Emissions in Coal Systems* prepared by STAP in response to the request of the GEF Council that STAP advise the Council about opportunities for reducing Greenhouse Gas (GHG) Emissions from coal systems.

In preparing this report STAP convened at workshop on Options for Improving Coal Supply Systems to Reduce Greenhouse Gas Emissions at the Institute for Environmental Studies, Vrije University, Amsterdam, 16-17 June 1997, in conjunction with the Ninth Meeting of STAP. This workshop was organized and chaired by Dr. Charles J. Johnson of the East-West Center, Honolulu, and brought together coal experts from around the world. This STAP report is based on discussions at the workshop, the workshop report prepared by Dr. Johnson (*Report of The STAP Workshop on Options for Improving Coal Supply Systems to Reduce Greenhouse Gas Emissions*), and additional analysis carried out by STAP.

This report was prepared by the STAP Working Group on Climate and Energy under the chairmanship of Dr. Robert Williams:

Robert Williams (lead author)
Stephen Karekezi
Jyoti Parikh
Chihiro Watanabe

Pier Vellinga
Chairman of STAP

29 September 1997

1. INTRODUCTION

In response to the request of the GEF Council that STAP advise the Council about opportunities for reducing greenhouse gas (GHG) emissions from coal systems, STAP (*i*) reviewed trends in coal consumption in selected major coal-consuming developing countries, (*ii*) reviewed trends in coal-related emissions restrictions in developing countries, (*iii*) considered risks to GEF's renewable energy portfolio that might arise from the launching of a coal initiative, (*iv*) identified a systems approach as necessary in identifying the optimal sets of technologies for addressing the GHG emissions challenge for coal, (*v*) reviewed alternative technologies and strategies for reducing GHG emissions, and (*vi*) identified an evolutionary approach to coal that would facilitate the realization of deep reductions in GHG emissions over the longer term, while providing near- and mid-term local environmental and economic benefits.

A major part of the assessment process was a Workshop on Options for Improving Coal Systems to Reduce Greenhouse Gas Emissions that STAP convened at Vrije University in Amsterdam, 16-17 June 1997. The workshop, which brought together coal experts from around the world, was organized and chaired by Dr. Charles J. Johnson of the East-West Center in Honolulu. Participants from Australia, China, India, Japan, South Africa and the United States presented formal papers, and informal presentations were also made by observers from ABB Carbon AB, Counseil General des Mines of France, and the International Energy Agency, and the World Bank.

2. GROWTH IN COAL CONSUMPTION

Coal consumption has been growing at a rapid rate of over 4.0 percent per year in Asia. It would double by 2020 if growth until then averaged 2.9 percent per year. While accurate projections of coal consumption cannot be made for 2020, a review of economic and electricity growth rate projections and plans of the coal-consuming countries of Asia indicates that current plans are consistent with a doubling of coal consumption from 1995 levels by 2015 to 2025.

There is greater uncertainty about future coal consumption in the rest of the world. However, if the use of coal were to grow 1 percent per year in the rest of the world while growing 2.9 percent per year in Asia, global coal consumption would increase 60 percent, 1995-2020. The implications for GHG emissions are distressingly large.

Even though the projections suggested here are unlikely to be accurate, there is strong evidence that substantial growth in coal consumption and coal-related GHG emissions will take place over the 1995-2020 period under business-as-usual conditions. The GEF should consider whether it can and should use its scarce resources to try to change ongoing trends by promoting more climate-friendly coal technologies.

3. TREND IN RESTRICTIONS ON COAL EMISSIONS IN DEVELOPING COUNTRIES

Mounting scientific concern that GHG-induced climate change is a serious problem justifies considering energy scenarios with restrictions on GHG emissions related to fossil-fuel use in both industrialized and developing countries. But while there is increasing awareness and concern about GHG emissions in many developing countries, the major coal-dependent developing countries have yet to take action to restrict coal use on a significant scale. In most developing countries, environmental activities relating to the coal industry and the coal-based power industry have been focused instead on: (*i*) coal technologies that can meet increasingly stringent environmental constraints on emissions of particulates, SOx, and NOx, and (*ii*) more energy-efficient technologies that can improve the economics of coal conversion.

Major actions to reduce coal-related GHG in coal-dependent developing countries appear to be unlikely in the foreseeable future, unless there is substantial financial and technical assistance from industrialized countries. Key to effective cooperation between developing and industrialized countries with regard to the coal and climate-change challenge is the interest of the major coal-using developing countries in acquiring advanced coal technologies that increase energy conversion efficiencies, reduce local pollution problems, and provide fuel and product flexibility. But developing countries have had great difficulties in finding the financial support for projects that would help launch such technologies in the market. Industrialized country support for coal projects that serve these needs while simultaneously addressing the challenge of climate change could attract considerable interest in coal-dependent developing countries.

4. RISKS TO GEF's RENEWABLE ENERGY PORTFOLIO

Concern was expressed at the workshop and also by an outside reviewer of the workshop report that if the GEF should launch a program relating to coal, the GEF renewable energy programs should not suffer as a consequence.

From a technical perspective there is no "silver bullet" to deal with climate change. Renewables will be very important, as STAP has previously shown (STAP, 1996), but it is also important to identify and pursue strategies for making fossil fuels more climate friendly.

The concern about the potential impact on GEF's renewables activities of a new coal initiative relates to the fact that the GEF has very limited resources. As STAP has shown (STAP, 1996), the characteristics of many renewable energy technologies are such that relatively modest resources of the scale that could be provided by GEF, appropriately targeted, could powerfully help launch the very embryonic renewable energy industries. In contrast, the world coal industry is large, and coal projects tend to require much larger investments than do renewable energy projects. Only a few projects could potentially consume a significant share of GEF's resources available for addressing climate change.

On the other hand, because large investments in coal are routinely made by the private sector in the developing world, GEF might be able to apply judiciously some of its very limited resources to reorient investments relating to coal in ways that are more compatible with climate-change concerns.

It may well be feasible and desirable for GEF to launch important new activities relating to coal without having to create first a new operational program relating to coal. As will be apparent from the discussion in this report, some of the most important coal-related activities needed in the near term to help put coal on a more climate-friendly path could probably be pursued in the context of existing operational programs (e.g., Operational Program No. 5: Removal of Barriers to Energy Efficiency and Energy Conservation, Operational Program No. 7: Reducing the Long-Term Costs of Low Greenhouse Gas-Emitting Energy Technologies, and the embryonic operational program relating to transportation). Getting experience with coal activities this way would help ensure a proper balance between coal and renewable projects as GEF evolves a coal strategy and understands better what its comparative advantage is in steering coal toward a more climate-friendly path.

5. THE IMPORTANCE OF A SYSTEMS APPROACH TO COAL

Workshop deliberations and other considerations led STAP to conclude that the optimal technologies and strategies for reducing GHG emissions from coal are best identified using a systems approach. GEF should look for opportunities to reduce GHG emissions throughout the entire chain of activities ranging from mining through end-use, for synergisms between different supply options [e.g., combined heat and power (CHP) instead of separate heat generation and electricity generation activities], for synergisms between coal and activities outside the coal industry (e.g., in the natural gas, oil, and chemical industries), and for synergisms between GHG mitigation goals and local environmental mitigation goals. Above all the GEF should identify and develop a strategic perspective for reducing GHG emissions from coal, to ensure that near-term actions are consistent with and supportive of long-term goals.

6. GHG EMISSIONS REDUCTION STRATEGIES

In what follows, opportunities for reducing GHG emissions are discussed in three categories: (*i*) near-term opportunities that could be adopted largely with existing technologies, (*ii*) options for reducing GHG emissions with advanced power-generating technologies, and (*iii*) a coal decarbonization/CO_2 sequestration strategy that would make feasible the achievement of deep reductions in emissions from the coal system.

6.1 Near-Term Opportunities

Near-term opportunities that could be adopted largely with existing technologies include: (*i*) management reforms at existing coal power plants, (*ii*) retrofitting existing coal plants, (*iii*) cofiring coal and biomass, and (*iv*) coal bed methane recovery. These options could have significant and measurable impacts in reducing GHG emissions over the course of the next decade.

6.1.1 Management Reforms at Existing Plants

A very low-cost near-term option for reducing coal-related CO_2 emissions is to introduce management techniques to improve the performance/efficiency of existing coal-fired power plants and large on-site generators (Siegel, 1997). Industrialized country experience has shown that proper training, analytical techniques and audits applied to improving power-plant performance can lead to increased plant availability, modest increases in thermodynamic efficiency and corresponding modest reductions in CO_2 emissions. While the emissions reduction at any one plant are modest, the reductions that could be achieved in a large number of plants in a relatively short period of time could be significant. An important advantage of these management techniques relating to climate change is that by making better use of existing capacity the need for new capacity is reduced, thereby buying time until new, more energy-efficient technologies are available.

Although commercially demonstrated, these techniques are not being widely used because of: (*i*) a lack of understanding of the methodology involved, (*ii*) a mindset among utility managers that building new plant capacity is more important than modifying existing plants; (*iii*) a lack of case studies demonstrating the effectiveness of such programs; and (*iv*) the lack of an institutional framework conducive to such programs in many developing countries.

6.1.2 Retrofitting Existing Plants

Retrofitting existing boiler and power plant capacity is less costly than installing new capacity in many cases and can lead to improved efficiencies and reduced CO_2 emissions. A properly functioning market will fulfill this requirement in industrialized countries, but struggling businesses in developing economies do not have access to adequate capital to upgrade their facilities. Of course the demand for power is growing so rapidly in developing countries that the GHG emissions of existing plants are soon dwarfed by the emissions from new plants.

6.1.3 Cofiring Coal and Biomass

Cofiring of biomass (especially various biomass wastes) and coal in coal plants is a strategy offering multiple benefits: (*i*) it leads directly to reduced GHG emissions as a coal substitute; (*ii*) until advanced biomass conversion technologies (e.g., integrated gasification/gas turbine or integrated gasification/fuel cell cycles) are commercially available, cofiring biomass in large-scale steam plants with coal will often lead to higher conversion efficiencies and more attractive economics than is possible with small biomass-only steam plants; (*iii*) it is an effective way to use those biomass resources (e.g., some agricultural residues) that are available only part of the year and are difficult to store; and (*iv*) by creating market demand for biomass, cofiring helps create a biomass fuel infrastructure and thus helps pave the way to wider future use of biomass for energy. Biomass cofiring is most easily accommodated with fluidized bed combustion units.

6.1.4 Coal Bed Methane Recovery

Coal deposits contain methane that is released either during coal mining or through drilling into coal seams to recover the methane. Methane recovery during coal mining has been carried out for many decades to reduce the risks of mine explosions. Over the past decade there have been rapid advances in the commercial recovery of coal-bed methane (CBM) in industrialized countries (particularly the United States); however the commercial potential of CBM in developing countries has yet to be demonstrated on a large scale.

Estimates of world methane emissions from coal mining range from 35 to 60 billion cubic meters per year. Because methane is a powerful greenhouse gas, there is considerable interest in CBM recovery in conjunction with coal mining as a climate-change mitigation strategy. For example, the GEF is likely to undertake a demonstration of CBM recovery and utilization project in India as a potentially low-cost option for reducing GHG emissions.

CBM recovery should be considered as a GHG mitigation strategy from a much broader perspective than this, however, both because methane is the most climate friendly of the fossil fuels and because CBM resources are huge, especially deep CBM deposits associated with coals that will probably never be mined.

Emissions from methane combustion are only slightly more than half of the emissions from coal combustion, per unit of energy contained in the feedstock. This climate benefit is amplified by the fact that typically methane can be utilized more efficiently than coal. Methane is also the cleanest of the fossil fuels, so that its use in place of coal provides substantial local environmental benefits as well.

Large amounts of methane are trapped in the pore spaces of some of these deep coals. Because coal is a microporous solid with large internal surface areas,[1] it has the ability to sorb large amounts of gas and can hold much more gas than the same rock volume of a conventional natural gas reservoir of comparable size, at the same temperature and pressure. In general, gas content increases with increasing coal rank.[2] Moreover, for coal beds saturated with CBM, the gas concentration (in normal cubic meters per tonne of coal) increases with the reservoir pressure, and thus with the depth of the CBM deposit, by nearly 30% for each doubling of pressure or depth (Rice et al., 1993).

CBM resources are substantial. Worldwide, resources are estimated to be 85 to 260 trillion normal cubic meters (Rice et al., 1993), with an energy value of 3,400 to 14,400 EJ. For comparison, remaining global recoverable conventional natural gas resources are estimated to be in the range 8,700 to 16,400 EJ, with a mean estimate of 11,800 EJ (Masters et al., 1994).

CBM currently accounts for 6% of total natural gas production in the United States; only 3% of the CBM recovered is associated with coal mining; the rest is from deep unminable coal. For CBM recovery, current practice is to depressurize the reservoir by pumping water out, which leads to desorption of the gas from the micropores of the coal matrix, its diffusion through the coal matrix to macrofractures, and its flow through these macrofractures to the wellbore for recovery. The process is simple and effective but slow and inefficient; there is typically a significant time lag (days to months) between the beginning of the dewatering process and the time when substantial gas recovery rates are realized. However, a new CBM strategy involving CO_2 injection holds forth the promise of being considerably more efficient (see Section 6.3.2).

6.2 Advanced Power-Generating Technologies

There are several advanced coal technology options for increasing power plant efficiencies from the 30-35% levels that are typical of existing coal plants to the range 40-50% (HHV basis). Here attention is focused on two sets of options: fluidized bed combustion and coal gasification based systems.

6.2.1 Fluidized Bed Combustion Technologies

In fluidized bed combustion, fuel is burned in a bed of fuel and other materials that behaves like a fluid, as a result of a gas passing upwards through the bed at a velocity sufficiently high for frictional drag to support the weight of the fuel and other particles but not so high as to transport the particles out of the bed. Typically only about 1% of the particles in the bed are active fuel particles, and bed temperatures of only 800 to 950 °C are sufficient to burn practically any fuel, including various low-quality fuels. Atmospheric pressure fluidized bed combustion (AFBC) systems are well established in the market and pressurized fluidized bed combustion (PFBC) systems are commercially ready.

6.2.1.1 Atmospheric Pressure Fluidized Bed Combustion Systems

AFBC technology is commercially established with both bubbling and circulating fluidized bed configurations. AFBC technologies were first deployed in the late 1970s, mainly for steam and process heat

[1] The internal surface area of these pore spaces amounts to tens to hundreds of square meters of per gram of coal!

[2] Typically lignites contain very little gas, while higher-rank medium- or low-volatile bituminous coal, semianthracite, or anthracite contain much more.

requirements. Until the mid-1980s the dominant technology was the bubbling atmospheric fluidized bed combustor (BAFBC), with thermal capacities of about 10 MW_{th}. Since then most new AFBC capacity additions have involved circulating atmospheric fluidized bed combustion (CAFBC) systems, which *account for about 70% of the 35 GW_{th} AFBC systems installed worldwide as of 1994.*

Modest energy efficiency gains are feasible with a shift from pulverized coal with flue gas desulfurization to AFBC technology. AFBC technology is well-suited for CHP applications for capacities in the range 50 to 150 MW_e (with CAFBC designs preferred to BAFBC designs, because of various environmental and operational advantages). AFBC technology also offers relatively simple strategies for dealing with air pollution constraints that are not especially demanding. However, use of AFBC systems can lead to significant GHG emissions in addition to the CO_2 emissions from coal burning–both from the use of large quantities of limestone or dolomite for SO_2 removal and from emissions of N_2O, a powerful greenhouse gas.

In AFBC units SO_2 emissions can be reduced by adding limestone ($CaCO_3$) or dolomite [$CaMg(CO_3)_2$] to the bed. Sulfur is removed according to the reaction:

$$CaCO_3 + SO_2 + 1/2\ O_2 \text{--->} CaSO_4 + CO_2.$$

Ideally, 1 mole of $CaCO_3$ is needed to remove 1 mole of SO_2. In practice, not all the limestone is effective in removing SO_2, so that extra limestone must be added to the bed to assure that a desired level of SO_2 removal is achieved. The extra limestone that does not react with SO_2 is typically calcined, according to:

$$CaCO_3 \text{---->} CaO + CO_2,$$

thereby forming CaO ("quicklime") and releasing CO_2 to the atmosphere. Up to 90% sulfur removal is practically realizable in AFBC units, typically with a Ca/S ratio *in the bed* = 2.0. The CO_2 emissions can be appreciable with relatively high-sulfur coals. For example, when SO_2 emissions are reduced 90% and Ca/S = 2.0 in the bed, the CO_2 emissions from the limestone are equivalent to 7% of the CO_2 emissions from combustion, when burning Pittsburgh Seam Freeport coal with 2.6% sulfur.

While conventional fossil fuel combustion technologies do not contribute significantly to N_2O emissions, atmospheric fluidized bed combustors do. N_2O is produced efficiently from fuel-bound nitrogen at the low operating temperatures characteristic of AFBC; N_2O emissions can be the CO_2-equivalent of 5% to 20% of the CO_2 from combustion (Williams, 1997a). Lower rank coals (subbituminous and lignite) as a rule produce less N_2O than bituminous coals. Also, it is commonly found that CAFBC units produce more N_2O than BAFBC units, possibly because of the longer residence times for the former (de Soete, 1993). Reducing N_2O emissions from AFBC units will be technologically challenging and is a focus of ongoing research (Williams, 1997a).

6.2.1.2 Pressurized Fluidized Bed Combustion Systems

When a fluidized bed combustor is pressurized, it becomes possible to produce extra electricity by expanding the flue gases from the fluidized bed combustor through a gas turbine, thereby improving overall system efficiency, while reducing the boiler size. Pressurized fluidized bed combustion (PFBC) and the integrated gasification combined cycle (IGCC) are the leading competing advanced coal-based power generating technologies. The principal advantage of PFBC technology in relation to IGCC technology is its simplicity, since it uses just one reactor (a combustor) compared to two (gasifier and combustor) for IGCC technology, which may give PFBC technology a near-term cost advantage compared to IGCC technology. The current generation of PFBC technology is characterized by efficiencies in the range 37-40%. A major limitation of present PFBC technology is that, unlike IGCC technology, it cannot take advantage of continuing advances in gas turbine technology. Future PFBC systems might be able to do this, but they will not have the simplicity that has been the major appeal of current PFBC designs. Several PFBC demonstration plants have been built (including a CHP plant with 135 MW of electrical capacity and a heat output capacity of 225 MW, owned by Stockholm Energy, at Värtan, Stockholm).

GHG emissions per kWh of electricity from combustion are lower for PFBC than for AFBC systems because of the higher thermodynamic efficiencies of PFBC units. Moreover, CO_2 emissions from the calcining of excess $CaCO_3$ to freelime are suppressed in PFBC units at sufficiently high operating pressures. Measured N_2O emissions at the PFBC CHP plant at Värtan, Sweden were the equivalent of about 10% of the CO_2 emissions from coal burning (Dahl, 1993; Williams, 1997a). With advanced designs it may be feasible to suppress N_2O emissions with PFBC.

In any case, if AFBC or PFBC are considered by the GEF as candidate technologies for reducing GHG emissions from coal, evaluation of the merits of these technologies as GHG-mitigation options must take into account assessments of these potential GHG emissions in excess of emissions from coal burning, on a case-by-case basis.

6.2.2 Coal Gasification and Integrated Coal Gasification/Combined Cycle Technologies

Since the feasibility of firing combined cycle power plants with coal via the use of closely coupled oxygen-blown coal gasifiers was demonstrated in the 94 MW_e Coolwater Project in Southern California, 1984-1989, there has been much progress in commercializing coal IGCC. This advanced coal technology can take advantage of the continuing improvements in gas turbine technology, making possible much higher efficiencies in power generation than what is feasible with the now mature steam-electric technology. Moreover, the key enabling technology, the oxygen-blown coal gasifier, has many other potential applications in chemicals and fuels productions.

Local air pollutant emission levels for coal IGCC plants are as low as from natural gas combined cycle plants–far lower than for conventional steam-electric plants equipped with stack gas emission controls. Volumes of solid waste that must be disposed of are also significantly less than for direct coal combustion systems (SFA Pacific, 1993). Moreover, unlike the situation for FBC technologies, there are no significant GHG emissions other than from coal combustion.

In 1994 a 41%-efficient 250 MW_e coal IGCC plant began operation in The Netherlands; in late 1995, a 262 MW_e coal IGCC plant began operating in Indiana, in the United States; several other coal IGCC plants are expected to be operational soon in various parts of the world (Stambler, 1996). With advanced gas turbines, it is expected that coal IGCC efficiencies will be able to reach 50%. Since the average efficiency of coal-fired power plants in China in 1995 was about 29%, HHV basis [30%, LHV basis (Jiang, 1997)], a 50%-efficient coal IGCC plant would emit less than 3/5 as much CO_2 per kWh as the average coal-fired power plant in China in 1995.

Although present-day coal IGCC plants are not yet competitive in strictly economic terms with conventional coal steam-electric plants with flue gas desulfurization, near-term improvements in gas turbine technology might make coal IGCC plants fully competitive in many circumstances (Stoll and Todd, 1996). In the meantime, coal-rich developing countries intent in pursuing this technology can pursue near-term activities that would facilitate later introduction of coal IGCC technology for central station power plants.

Consider that China is already using many modern coal gasifiers in the chemical process industries.[3] This activity might be extended to include the coproduction of chemicals (e.g., ammonia) and town gas. One option would be to build a future ammonia plant with enough coal gasification capacity to accommodate both ammonia production needs and town gas for a nearby community. Since modern coal gasification technology is capital-intensive, it is highly desirable to maintain high capacity utilization of the gasifier equipment throughout the year. This could be achieved by producing methanol from the coal gas for rural applications (esp. for cooking) when demand for town gas is low. A highly-efficient use of the town gas could be in small reciprocating engines for CHP applications in apartment buildings, commercial buildings, and factories. Town-gas-based CHP technologies are commercially available and highly energy efficient compared to the separate production of electricity and heat; they would be very cost-competitive today in markets where energy prices reflect full costs.

A very important and large market opportunity for coal IGCC technology is for CHP in the basic materials process industries (e.g., chemicals, pulp and paper, steel, petroleum refining), which have large baseload process heat requirements. For these applications coal IGCC technologies will be able to produce several times as much electricity per unit of process steam required than can conventional steam turbine technology. Because electricity is worth much more than heat, CHP with coal IGCC can bring much more value to the producer than can CHP with steam turbine technology. Rapidly industrializing countries represent ideal markets for such CHP systems because the basic materials processing industries are growing rapidly. These industries have the potential of becoming major providers of very cost-competitive and clean baseload power in these countries, if policies are in place that make competitive electricity prices available to these producers for the electricity they can make available to electricity grids.

Still another way to gain early experience with IGCC would be to gasify refinery residual oils (Stoll and Todd, 1996). In several ways, plant costs will often be lower for heavy oil gasification than for coal gasification. For example, solids handling, crushing, and feeding systems are not needed. Moreover, the generally lower levels of ash in heavy oils means less fouling of syngas coolers, so that lower cost designs might be employed. In addition, heavy "refinery bottom" oils tend to be cheap—sometimes even cheaper than coal on an equivalent energy basis. As a result a heavy-oil integrated gasification/combined cycle power plant located, say, at a refinery, will often be able to produce electricity with today's technology at lower cost than a coal steam-electric plant. While this is only a niche market, it offers a basis for gaining experience with gasification technology relating to power generation before the technology is competitive for coal applications in central station plants.

Even when such promising early market opportunities for coal gasification and IGCC technologies have been identified, there will be institutional barriers to their adoption. The barriers to the introduction of these advanced technologies vary from: (*i*) energy prices distorted so far below market prices that it is

[3] More than 20 Texaco gasifiers are operating, under construction, or on order for the production of chemical fertilizer, methanol, town gas, and oxochemicals. In addition, about six Shell gasifiers and at least one Lurgi gasifier are being used to produce ammonia from coal.

difficult to adopt town gas and CHP strategies, (*ii*) a lack of experience using these technologies in developing countries, (*iii*) industry reluctance to introduce new technologies with higher real or perceived risks, (*iv*) banker reluctance to fund new technologies that may not be fully proven at commercial scales, (*v*) lack of enforcement of environmental regulations, which businesses to continue to use higher polluting coal-burning technologies, to (*vi*) institutional barriers within governments and international institutions may discourage the introduction of innovative new technologies.

6.3 A Coal Decarbonization/CO_2 Sequestration Strategy for Achieving Deep Reductions

An idea advanced at the workshop for using coal in a climate-friendly way is to separate the energy value of the coal from its carbon content, by decarbonizing the coal to produce hydrogen and isolating from the atmosphere the CO_2 separated from the hydrogen at the production plant (Williams, 1997a). This option makes possible continued use of coal at substantial scale while reducing CO_2 emissions to the atmosphere to very low levels and simultaneously virtually eliminating local air pollutant emissions associated with conventional coal combustion technologies.

6.3.1 Producing Hydrogen from Coal

All the required technology for making hydrogen from coal is commercially available. The key enabling technology is modern oxygen-blown coal gasification. This technology produces from coal "synthesis gas," a gaseous mixture consisting mainly of carbon monoxide and hydrogen, at high efficiency. The carbon monoxide in this synthesis gas is then reacted with steam in so-called "water-gas shift reactors," producing more hydrogen plus carbon dioxide. The net effect of gasification and shifting is thus to produce a gaseous mixture consisting mainly of hydrogen and CO_2. Various commercial technologies are available for separating the hydrogen (with up to 99.999% purity) from the CO_2 in the resulting gaseous mixture. For modern plants the hydrogen produced this way would have an energy content greater than 60% of the energy content of the coal from which it is derived, and the CO_2 separated from the hydrogen at the production plant would account for nearly all of the carbon in the original coal feedstock; CO_2 separation and sequestration in isolation from the atmosphere could be accomplished at a small increment to the cost of producing the hydrogen (Williams, 1996). This incremental cost could be reduced if sequestration of the separated CO_2 provided economic value, as will sometimes be the case (see below). With sequestration of the CO_2 separated at the hydrogen production plant, the only CO_2 emissions associated with hydrogen production from coal arise from the production of external electricity and heat needed to make the hydrogen, which are modest even if these inputs are provided by burning coal (Williams, 1996).

6.3.2 Sequestering the Separated CO_2 in Coal-Rich Countries

There are various possibilities for sequestering the separated CO_2: in depleted oil and gas fields, deep saline aquifers, deep CBM reservoirs, and perhaps even the deep oceans. Although imperfectly understood, the capacity for underground sequestration might be adequate to hold securely hundreds and even thousands of gigatonnes of carbon as CO_2 (Socolow, 1997). For comparison, annual global CO_2 emissions from fossil fuel burning today amount to about 6 gigatonnes of carbon.

For coal-rich countries with deep coal resources (e.g., China, India, Botswana) a promising sequestration option is in CBM reservoirs that are so deep that mining the coal is impractical. Injecting CO_2 into these coal beds might prove to be an economical strategy to recover from these coal beds methane for use as a fuel, leaving the CO_2 behind in the coal bed (Gunter et al., 1997).

As noted earlier (see Section 6.1.4) the current process for recovering deep CBM, though simple and effective, is slow and inefficient. An alternative strategy that holds forth the prospect of being far more efficient is gas injection; for this purpose CO_2 is especially promising because it is twice as adsorbing on coal as methane; it can therefore efficiently displace the methane adsorbed on the coal (Gunter et al., 1997). Carbon dioxide injection makes it possible to maintain reservoir pressure and produce methane gas quickly. As CO_2 moves through the reservoir it displaces methane; it has been found that very little of the injected CO_2 shows up in the production well until most of the methane has been produced. Thus the prospects for permanent sequestration of the injected CO_2 are good. Of course, sequestration of CO_2 in the coal bed would prevent subsequent mining of the coal. However, for much of the coal lying in deep beds that contain substantial quantities of CBM and that would be especially favorable sites for CO_2 sequestration, mining the coal would often be too costly.

6.3.3 Marketing the Produced Hydrogen

The key to making this overall strategy work is the existence of a market that places a high value on hydrogen. Although fuel markets for hydrogen do not yet exist, hydrogen is produced at significant levels throughout the world for chemical process applications, mostly at oil refineries and for ammonia production. For example, about 5% of natural gas produced in the United States is used to produce hydrogen for these applications. The ongoing trends to the use of heavier crude oils and to reformulated gasolines for meeting tightening air quality goals are leading to a growing demand for hydrogen at oil refineries, while growing populations are driving up the demand for ammonia for fertilizer. Because its conventional natural gas supplies are limited, China produces hydrogen as an intermediary in the production of ammonia and other chemicals from coal through coal gasification, as well as from natural gas.

When ammonia is produced from coal this way, a stream of byproduct CO_2 is generated. If the ammonia plant is associated with a plant for making urea for fertilizer from the ammonia (which is often the case), some of this byproduct CO_2 (0.5 moles of CO_2 per mole of ammonia) is used for urea manufacture. However, a comparable amount of excess CO_2 is generally also available. An alternative to venting the excess CO_2 is to use it to stimulate methane recovery from deep coal beds for those ammonia plants that are sufficiently close to appropriate deep CBM deposits.

In the future hydrogen could also be used as a fuel. The prospects for using hydrogen as a fuel are especially good if low-temperature fuel cells become well-established in the market. Fuel cells are devices that convert the chemical energy in a fuel directly into electricity without first burning the fuel to produce heat; fuel cells can be much more energy-efficient in making electricity than conventional combustion-based technologies. The natural fuel for such fuel cells is hydrogen. Storage of hydrogen onboard vehicles could be accomplished by using light-weight pressurized hydrogen storage canisters, unless advanced concepts (e.g., high energy density carbon nanostructure storage technologies) can be successfully launched in the market.

Low-temperature fuel cells might be supplied initially with a hydrocarbon fuels (natural gas or a liquid hydrocarbon fuel) that is converted at or near the point of use into a hydrogen-rich gas that fuel cells can use; this is the approach that will probably be followed in many industrialized countries. However, there would be strong internal market pressure to shift to hydrogen as soon as hydrogen infrastructure could be put into place, since these fuel cells "prefer" to be fueled by hydrogen that is produced centrally and distributed by pipelines to users (Williams, 1997b). Those developing countries that don't already have well-established hydrocarbon fuel infrastructures in place have the opportunity to "leapfrog" the already industrialized countries directly to a hydrogen economy.

At present, the two leading-candidate low-temperature fuel cells are the phosphoric-acid fuel cell (PAFC) and the proton-exchange-membrane fuel cell (PEMFC). The PAFC is already commercially established for distributed combined heat and power (CHP) applications in apartment buildings and commercial buildings. Typical commercial units produce electricity at a scale of 200 kilowatts, with the delivered fuel being natural gas that is "reformed" at the site to a hydrogen-rich mixture of gases that the fuel cell can use. Such fuel cells could also be used with hydrogen derived centrally from coal that is piped to distributed users.

The PEMFC offers the potential for much lower costs than the PAFC. Moreover, its much higher power density makes it an attractive candidate for use in transportation. Automotive applications of PEMFCs are a target of private- and public-sector R&D programs in Europe, North America, and Japan; several prototype PEMFC cars have already been built. Mass produced, such fuel cells might become fully competitive with the internal combustion engine for vehicular applications (Williams, 1997b). Initial applications of PEMFCs for automotive markets are targeted for the period 2005-2010. PEMFCs will be commercially available for distributed CHP and transit bus applications before 2000. PEMFCs would also be well-suited for applications in 2- and 3-wheeled vehicles, trucks, and locomotives.

Fuel cells operated on hydrogen derived from coal offer the potential for using coal at extraordinarily high efficiency and with zero local pollutant emissions, without the need for pollution-control technologies. The centralized hydrogen production plants themselves can be designed to be as clean as coal IGCC power plants, which are as clean as natural-gas combined-cycle power plants. Moreover, with centralized hydrogen production the separated CO_2 could be sequestered underground (e.g., in deep CBM reservoirs).

The high energy efficiency of fuel cells makes it possible to provide high levels of energy services from coal with relatively modest lifecycle CO_2 emissions, even without sequestration, as is illustrated with a thought experiment. Suppose that in China there will be 350 million fuel cell cars in 2050 (one for every 4.4 persons) driven on average 15,000 km a year and operated on coal-derived hydrogen that is stored onboard the cars as a compressed gas. Such cars would typically have a fuel economy of about 2.35 liters of gasoline-equivalent per 100 km (100 miles per gallon of gasoline equivalent) (Ogden et al., 1997). The lifecycle CO_2 emissions from the hydrogen production system needed to support these cars would be about 180 million tonnes of C without sequestering the separated CO_2 or about 50 million tonnes of C with sequestration. For comparison total CO_2 emissions from burning of fossil fuels amounted to 720 million tonnes of C in 1990.

7. AN EVOLUTIONARY APPROACH TO ACHIEVING DEEP REDUCTIONS IN GHG EMISSIONS

Of the coal technologies reviewed here, the combination of coal decarbonization to produce hydrogen and CO_2 sequestration offers the greatest potential for using coal in a climate-friendly way. The key enabling technology for *decarbonization* is modern coal gasification technology. For coal-rich countries, a key enabling option for *sequestration* is injection of CO_2 into deep beds of unminable coal to recover CBM as an energy source.

A coal-use strategy that emphasizes these key enabling technologies so as to provide near-term and mid-term benefits would make it possible to evolve over the longer term to a coal economy based on hydrogen with sequestration of the separated CO_2.

The following is an exemplary set of near-term (next 1-5 years), medium-term (5-15 years) and long-term (15+ years) actions that might make up such a strategy.

7.1 Near-Term Measures

Discourage the use of those coal technologies that exacerbate GHG emissions, as a means of encouraging gasification-based technologies.

Examples of coal technologies that would exacerbate GHG emissions problems are atmospheric fluidized bed combustion and direct coal liquefaction. The problems with AFBC have been noted (see Section 6.1.1). Direct coal liquefaction, which involves producing a synthetic crude oil from coal that can be refined to produce traditional hydrocarbon fuels,[4] generates considerably more GHG emissions in the production of these fuels than does the refining of petroleum crudes;[5] for this reason the Energy R&D of the President's Committee of Advisors on Science and Technology has recommended in its report to the President of the United States that R&D on direct coal liquefaction technology be eliminated from the U.S. energy R&D program (PCAST Energy R&D Panel, 1997).

Enact strict local air pollution regulatory measures in ways that would encourage the adoption of clean-coal technologies such as modern gasification technologies.

Introduce gas price reforms that would facilitate the expanded use of town gas derived from coal as an alternative to home use of direct coal combustion in countries where coal is so used today. (Town gas is currently supplied to about 40 million people in China.)

Enact policies that would facilitate the use of small reciprocating engines for CHP applications of this town gas at apartment buildings, commercial buildings, and factories.

Encourage the introduction of modern coal gasification technology for town gas production.

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[4] Alternatively, liquid fuels can be made from coal via indirect liquefaction, a process that begins with oxygen-blown coal gasification to produce synthesis gas . With synthesis gas it is feasible to provide various clean liquid fuels (e.g., methanol and Fischer-Tropsch liquids), as well as hydrogen, ammonia, and a wide range of other chemicals. In the coal R&D community the focus of activity today is generally on indirect liquefaction instead of direct liquefaction, largely because the liquid fuels that can be produced via indirect liquefaction make it easier to address increasingly stringent local environmental concerns than is the case for liquid fuels derived from aromatic-rich coal crudes. At present there is considerable global interest in making Fischer-Tropsch liquids from natural gas, as exemplified by the recent announcement by Exxon that it will build a plant in Qatar that will produce 100,000 barrels/day of Fischer-Tropsch liquids from natural gas. One of the major products that can be produced using the Fischer-Tropsch process is a clean synthetic middle distillate fuel (it contains zero sulfur and no aromatics) that is well-suited for use in compression-ignition internal combustion engines.

[5] In addition, it is difficult to make liquids derived from aromatic-rich coal crudes as clean as is increasingly being required for liquids derived from petroleum crudes (e.g., to reduce to low levels the concentrations of the carcinogen benzene and other toxics) in order to address environmental health concerns.

Introduce integrated gasification/combined cycle (IGCC) technology in applications where it is cost-competitive today (e.g., using low-cost residual refinery fuels), *as a means of gaining experience with this technology and facilitating a transition to the use of IGCC technology with coal.*

Carry out pilot investigations of the potential for methane recovery from deep (unminable) coal beds via CO_2 injection.

This should be done in collaboration with ongoing and planned investigations in North America for using CO_2 injection for recovery of methane from deep coal beds. One possible source of CO_2 might be at an existing plant that produces ammonia from coal. (In China some 25-35 million tonnes of coal are gasified annually to produce ammonia.)

Carry out small-scale demonstration projects involving the use of hydrogen fuel cells in transportation (for buses and 2- and 3-wheel vehicles) and for distributed CHP applications.

The hydrogen used as fuel for these demonstrations could probably be provided by excess supplies of hydrogen now produced for industrial applications (e.g., ammonia production). Where demonstrations are desired and such hydrogen supplies are not available, hydrogen derived electrolytically from off-peak hydroelectric power might be used instead.

7.2 Mid-Term Measures

Introduce IGCC technology for CHP applications in the energy-intensive basic materials processing industries.

Launch major projects involving methane recovery from deep (unminable) coal beds via CO_2 injection and sequestration.

The recovered methane could be used in a wide range of natural gas applications, including combined cycle power generation.

Carry out demonstration projects involving the use of fuel cells for "heavy-duty" transportation applications, including locomotives.[6]

For these applications consideration should be given to both hydrogen and methanol derived from

[6] The electric drive trains and onboard electricity generation offered by fuel cells are especially appealing for mountainous railroad-intensive transport systems. For example, the railroads in China involve many steep grades, especially in mountainous regions in western China. Steep grades require locomotives that can deliver high torque at low speeds. The best way to accomplish this is to use electric-drive trains. China has been expanding the use of electric locomotives in the west, with the needed electricity provided by external power lines. But the shift to electricity is inhibited by the high capital costs of making adequate clearance for these lines in the many long tunnels in these mountainous regions, as well as by the temporary loss of needed rail capacity during periods of reconstruction. Such problems could be avoided by use of fuel cell locomotives, which provide electric drives based on onboard power generation. Fuel cells might make it possible to increase rail capacity in China without expanding rail lines.

coal as energy carriers delivered to vehicles.

7.3 Long-Term Measures

Commercialize hydrogen fuel cell technology in transportation markets, emphasizing buses, 2- and 3-wheel vehicles, and locomotives.

Commercialize hydrogen fuel cell CHP systems for apartment building and commercial building applications.

Produce hydrogen from CBM and from coal, with injection and sequestration of the separated CO_2 into CBM reservoirs for stimulating additional recovery of methane from coal beds.

This hydrogen would serve both industrial markets (e.g., ammonia production and petroleum refining) and the new hydrogen fuel markets.

8. CONCLUSIONS

In conclusion, STAP recommends that:

- Whatever the GEF decides to do in relation to coal should not be at the expense of activities relating to renewable energy technologies.

- If the GEF decides to launch a program relating to coal, it should take a systems approach, looking for opportunities to reduce GHG emissions throughout the entire chain of activities ranging from mining through end-use, for synergisms between different supply options, for synergisms between coal and activities outside the coal industry, and for synergisms between GHG mitigation goals and local environmental mitigation goals. This approach would help identify coal options that are sensible from local environmental and economic perspectives as well as helpful in dealing with the challenge of climate change.

- If the GEF decides to launch a program relating to coal, it should be in the context of a strategic plan in which near-term actions are consistent with and supportive of long-term objectives.

- The option offering the greatest potential for using coal in a climate-friendly way is to separate the energy value of the coal from its carbon content, by *decarbonizing* the coal to produce hydrogen and *sequestering* the CO_2 separated from the hydrogen at the production plant.

    * The key enabling technology for *decarbonization* is modern coal gasification technology, which offers multiple local environmental and economic benefits as well as climate benefits. Key initial steps in the development of a coal strategy designed around modern coal gasification technology are energy pricing reforms and effective local environmental policies.

    * For coal-rich countries a key option for *sequestration* is injection of CO_2 into deep beds of unminable coal to recover coal bed methane as an energy source, a strategy that also offers multiple local environmental and economic benefits as well as multiple climate change

benefits. A key initial step is to explore the potential for enhanced methane recovery from deep coal beds using excess CO_2 at plants that produce ammonia from coal; CO_2 sequestration would be a "free byproduct" of such activity.

Most of what should be done in the near term relating to both decarbonization and sequestration would be desirable even if there were no climate change challenge.

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ALLOCATING RISK AMONG CCT PROJECT STAKEHOLDERS TO ENSURE SUCCESS

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I. OVERVIEW

Clean Coal Technology Projects (CCT) have all the normal risks associated with power plant projects, in addition to the risks involved with developmental technologies. The increased risks associated with delivery of these technologies, however, are offset by the significant benefits from CCT's, which include significantly reduced environmental impacts combined with improved generation efficiencies. In order to achieve these benefits, CCT project risks need to be allocated appropriately and managed in order for projects to be financed, built and operated successfully. This paper will address some practical risk allocation guidelines and mitigation strategies for overcoming the financial challenges for CCT's and insuring project success.

A systematic approach to risk management for financing and project development begins with a realistic risk allocation during the initiation of the various contracts. Realistic risk allocation involves an equitable sharing of risk rather than a blind allocation. During the preconstruction development phase, the owners and the other project participants should determine the optimum risk distribution, the overall form for the contracting arrangements and the team building requirements for their particular project. The team building approach helps manage risk and reduce conflict.

The focus throughout must be on appropriate "risk sharing" by all the stakeholders in the project. This would include developers, investors, contractors, designers, equipment suppliers, fuel suppliers, operators, consumers and government entities. As discussed below, risk sharing involves allocating risks to the party who is in the best position to control that risk. Thus, each stakeholder in the project maintains some extent of control over its destiny. A number of contractual relationships will ultimately describe the precise risk allocation among the stakeholders. (See Figure 1.)

- **Advantages of Risk Sharing over Risk Shifting in Contracts**

The development of any major project involves substantial risks; risks in the necessary approvals, design, time, cost, quality, performance and the potential revenue stream and utilization of the project. In the past, parties to the process frequently focused on "risk shifting" and “risk avoidance.” This aversion to taking responsibility is both a product of and contributing factor to the litigious nature of the industry. To avoid litigation and disputes, the focus must be on “risk sharing.”

Industry studies indicate that contracts, which attempt to shift risks to parties, which have little or no control, are not cost effective. These risk shifting contracts are ineffective because they: (1) reduce contractor competition, (2) increase prices due to increased contractor contingencies, and (3) increase costs and reduce efficiency due to increased project disputes. These studies have concluded that the imposition on contractors of risks, which they cannot manage and control is a primary cause of contract disputes.

Among other things, risk shifting clauses tend to create an adversarial relationship from the very start of a project. Walls are built rather than bridges, and the chance of a legal conflict increases greatly. In contrast, when risks are shared equitably, the need to operate defensively is eliminated and the chance of conflict is greatly reduced. When the parties share the risk, their working relationship becomes more cooperative and less adversarial.

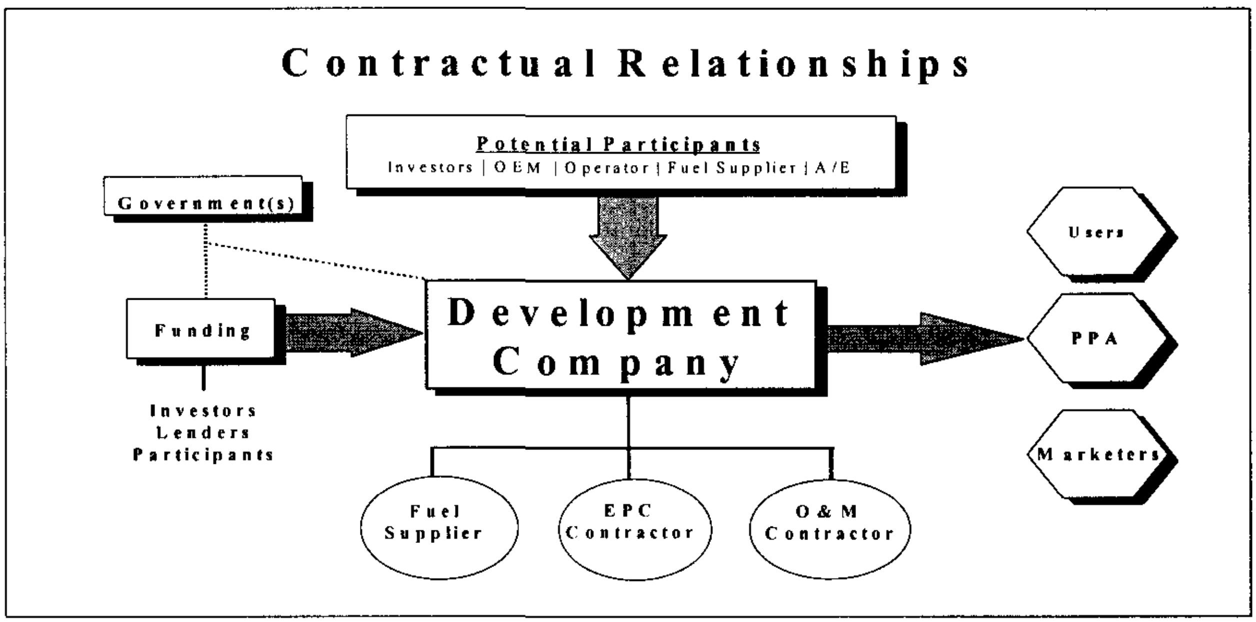

Figure 1

- **Allocating Project Risk in Stages**

Project risk can be divided into three stages: (1) development, (2) design and construction, and (3) operation and maintenance (See Figure 2). In many situations, a plan of finance targeted for each stage will often minimize costs. Each stage can be tailored individually to the unique interests of different contractors and investors seeking different investment risk/return tradeoffs. Establishing a financing and contracting plan for each stage helps to avoid a "high risk" profile for an entire project.

1. **Development Stage.** The development stage is the phase where preliminary project design, planning, cost estimation, environmental impact assessment, permitting, and right-of-way acquisitions occur. Because this phase has the greatest uncertainties and financing risks, it is viewed by capital markets as highly speculative. As a result, the developer often has difficulty in securing financing for preconstruction expenditures. When the developer does obtain financing, it generally is at a higher interest rate than would be charged for financing the later stages of the project. Frequently, potential participants provide services at risk during this stage, until financial closing.

2. **Design and Construction Stage.** The construction stage also has financing risk, although the risks may be more definable. The financing risks exist for various reasons, including the possibility of construction difficulties, unforeseen circumstances, delays and overruns. While interest rates on construction financing are lower than on preconstruction financing, rates can be high due to the length of time that investor capital will be tied up. However, by choosing the proper contract delivery approach, which guarantees the maximum cost, provides for fast track delivery and allows for liquidated damages for delay and preferences, the risks can be mitigated. A highly qualified contractor team also controls the risk at this stage.

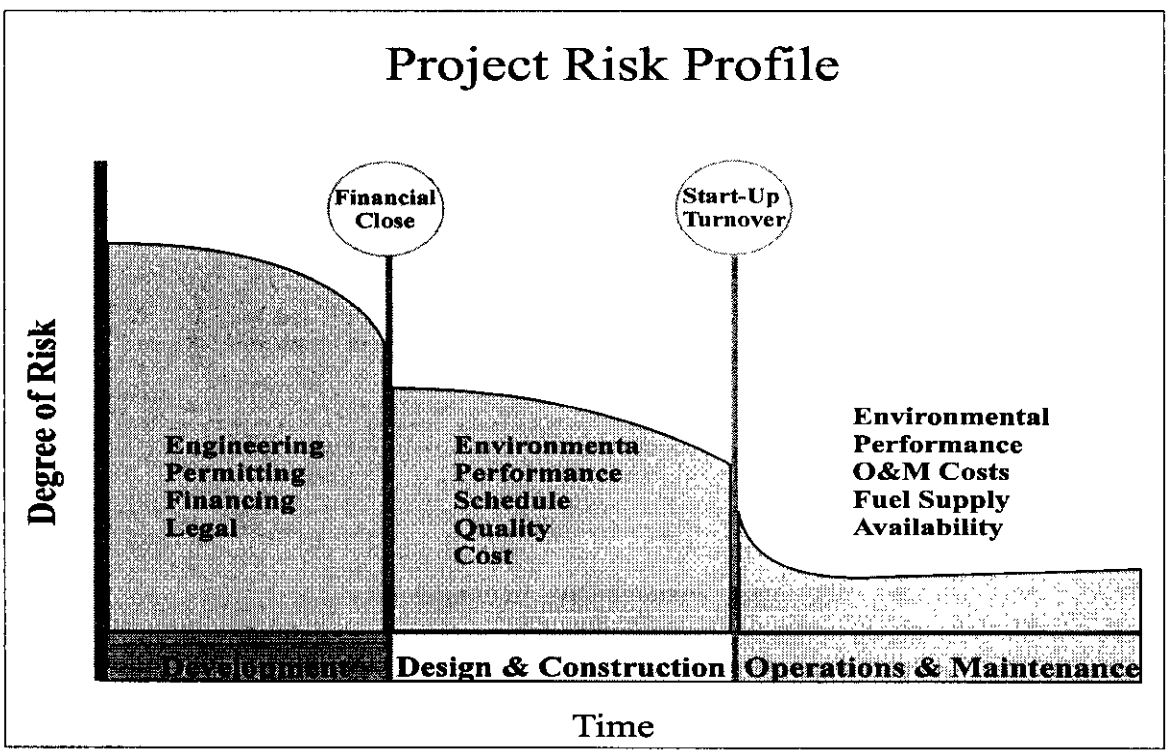

Figure 2

3. **Operation and Maintenance Stage.** The operational stage has the least financing risks, although other risks do exist. The major risk of this stage is whether the developer will generate sufficient income from the project to repay the principal and debt and achieve a return on its investment. On the cost side, there is ongoing risk in fuel, operation and maintenance and plant performance.

II. IDENTIFYING PROJECT RISKS FOR ALLOCATION

Before risks can be reasonably allocated, they must be identified. The effort in identifying, quantifying and assigning risks prior to and during contract negotiations is critical to project success. Figure 3 provides a process risk overview. The following is a general discussion of some of the major risk areas in the process that should be addressed.

1. **Regulatory Risk.** Regulatory risk is that arising from the need to satisfy requirements expressed in laws or regulations. Typical regulatory requirements involve taxes, health and safety measures, and environmental considerations such as limitations on discharges and emissions. Many regulatory requirements are reflected in the need to obtain permits or other governmental imprimaturs. The costs imposed by meeting regulations in effect at the time the particular contract is entered into are more or less quantifiable and can be reflected in the contract and the price depending on which party is assuming the risk. The regulatory requirements may change, however, between the time of contracting and completion. Accordingly, the contract should identify at what point compliance with regulatory mandates is to be measured (e.g., substantial completion), and allocate the risk of any subsequent changes accordingly.

2. **Governmental Risk.** Governmental risk refers to the possibility that the country or other geopolitical entity in which the project is to be constructed and operated will undergo a political, economic, or social change that impacts the project after it is started. Such risk is most prevalent in developing countries. Examples include wholesale changes in governments, expropriation, anarchy, warfare, terrorism, sabotage, and currency problems (e.g., devaluation, exchange rate fluctuations, and convertibility controls). Such factors may affect any or all of the project stakeholders' desire or ability to continue with the project.

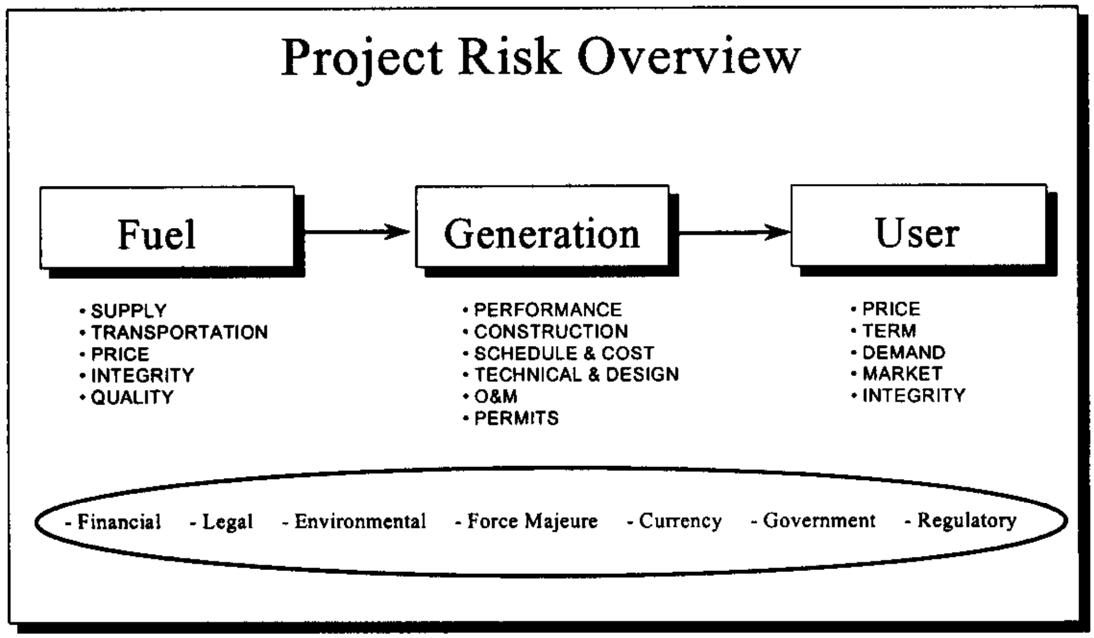

Figure 3

3. **Fuel Risk**. Fuel risk refers to the availability, price and quality of fuel to fire the plant. The risk is that a shortage of acceptable fuel will increase the price to a point where continued operations become uneconomic. The risk of fuel price and availability will be allocated among the owner, operator and user. In some instances, one or the other party will assume the risk to a certain point, at which point it will be shared or shift entirely. Where a party other than the plant operator is to assure fuel availability, there may be a "put-or-pay" agreement where the party assuming the risk guarantees the availability of a certain quantity and quality of fuel. If unable to deliver the agreed fuel, the party at risk must pay the operator a predetermined sum. Where there is a power purchase agreement that commits a customer to a specified buy, often fuel costs are indexed or passed through to the customer, so that it bears the risk of fuel escalation.

4. **Market Risk.** Market risk addresses whether there will be a sufficient customer base to absorb the output of the plant to (a) justify the investment in the plant's construction and (b) permit its continued operation. In an era of deregulation, market risk must consider the effect of competition in the intended market, including the need for lower prices to meet that competition. Market risk is especially important where project financing is to be employed, i.e., financing is based on projected revenues. Market risk may be difficult to assess because it is based on projections of future demand as well as price.

5. **Construction Risk.** Construction risk includes the risk of whether the project can be completed on time, or for the agreed price. Construction risk also addresses whether the plant will perform as promised. Numerous factors may impact the construction process. These include design deficiencies, owner changes, differing site conditions, weather, labor problems (e.g., strikes or skilled labor shortages), material and equipment availability, health and safety concerns, currency fluctuations, the availability of necessary utilities, and the regulatory and governmental risks discussed above.

6. **Performance/Operating Risk.** Performance/operating risk refers to operation of the completed plant, and usually falls upon the operations and maintenance ("O&M") contractor. Once presented with a set of assumptions as to the capability of the plant to be constructed, the O&M contractor may be required to guarantee a certain output level. Any shortfall will result in a reduction of the contract price. At some point, the shortfall will be so great as to justify termination of the O&M contractor. Factors impacting performance/operating risk include some of the elements of the other risk factors, including regulatory, governmental, changes in the operations, fuel risks, market risks, labor problems, currency fluctuations, and the availability of utilities. Compliance with environmental concerns also is a significant risk in performance/operations.

7. **Technology Risk.** Technology risk refers to the possibility that the technology/methodology used to produce power will not perform as anticipated. This risk will encompass the spectrum from complete failure (in the case of new, innovative, or unproven technologies) to less-than-anticipated results (where technology has been used with varying degrees of success) to relative certainty of success (where proven technologies are employed). Depending on where the technology employed falls on this spectrum, the greater or lesser the risk that will have to be allocated among the parties.

8. **Force Majeure Risk.** Force majeure risk means a risk that is beyond the control of all parties to the contract, most typically in the nature of acts of God and unusually severe weather. In contracts, it can also be defined to include such things as strikes at a manufacturing site and delays in transportation. Often a "force majeure" clause is used that will excuse any party's performance in the face of occurrences (including governmental risks) beyond any party's control.

III. BUILDING TEAMS TO FACILITATE RISK SHARING

Risk sharing involving the development stage can be spelled out in a memorandum of understanding and later structured as a consortium or joint venture agreement. Ultimately a special purpose entity may be used. These agreements must address the sharing of risks and rewards among the participants for the development effort. The construction stage typically involves two contract delivery systems; either a construction management, multiple prime arrangement or a design-build type agreement. Variations in the importance of the risk factors affect the initial contracting choice. Power projects frequently use a design-build or EPC (Engineer, Procure, Construct) approach to attract financing and control risks. These various agreements are described below.

1. **Teaming Agreements.** A teaming agreement has two or more entities joining on the basis of obtaining projects. In a teaming agreement, typically the prime contractor will agree to use a particular subcontractor, the other team member. In return, the subcontractor agrees not to team with others on the project and not to bid itself as a prime. Although a teaming agreement usually establishes a prime-subcontractor relationship, it may also be a joint venture.

   The relationship between the parties is expressed in a teaming agreement. The parties to the teaming agreement remain free to sell their services to others not involved in the project. In an exclusive arrangement, the prime contractor may want to place controls on how much the teaming agreement subcontractor can charge since the subcontractor will be a sole source. A teaming agreement need not be exclusive. The prime contractor may reserve the right to contract with others or do the work itself. Similarly, a subcontractor may seek the seek the right to team with others.

   In order to permit the exchange of information between parties to determine whether a teaming agreement is in their best interests, the parties may enter into a technology exchange agreement designed to protect exchanged proprietary information. The teaming agreement itself should contain a confidentiality agreement that expresses the parties' agreement to provide each other with necessary data. The teaming agreement may also contain a licensing agreement that places restrictions on the use of data by the receiving party. A teaming agreement will usually be of definite duration, usually until the project is awarded. At that juncture, the parties usually will enter into a subcontract. The teaming agreement should specify when and under what circumstances it may be discontinued.

2. **Joint Ventures.** A joint venture is a business entity formed to undertake one project, i.e., it exists for a limited duration. Its hallmark is shared responsibility among the joint venture partners. Joint ventures may provide a necessary combination of financing (equity or otherwise), expertise, and sponsor diversification in international projects. Usually the entity formed is a partnership, although it may be a corporation. If the joint venture is seen as existing for more than a single purpose, it may be seen as a general partnership with the members exposed to unlimited liability. Antitrust or other laws governing business associations may apply to joint ventures.

All actions are taken in the joint venture's name. The parties to a joint venture have mutual control, although that control need not be equal. The joint venture agreement should identify the rights and obligations of the partners and provide for the administration, termination, and dissolution of the joint venture. The joint venture agreement may identify a managing partner who will be responsible for the day to day operations of the joint venture. The joint venture agreement should identify the contributions expected of each partner, including allocations of work responsibility. There is a sharing of profits and losses as stated in the joint venture agreement. Anticipated profits usually are divided up among the stages of the work, and then further subdivided within each stage. Each venture is liable individually for the venture's debts.

3. **Consortiums.** Consortiums are frequently used today in international development projects. The typical group would include one or more developers, engineer-constructors, manufacturers and financing organizations. The consortium seeks projects and shares the costs of development through in kind services or direct funding. Risk is shared by percentages called out in the agreement. Upon financial closing, the consortium would be replaced by a more formal special purpose entity for that project. A consortium agreement is used in international contracting where equipment installations will form a major part of the project, e.g., generators and turbines. The construction contractor and the major equipment suppliers will coordinate their offers to the owner and agree to joint and several liability. If accepted, the offers will result in a single contract with the owner. Specific risks are assumed by individual members directly through interrelated contract agreements among the members.

4. **Special Purpose Entities.** A special purpose entity ("SPE") is an organization created to limit liability of the participants and to act as the contracting vehicle for a particular project. The SPE is the primary interface with the customer, usually through a long-term service agreement covering design, construction, operation and maintenance. It may be formed by any number of parties, including the construction contractor, designer, operations and maintenance contractor, and possibly third party investors. It may be financed through use of debt and equity. The SPE, in turn, contracts for the design, construction, and operation and maintenance services, most likely to the companies, which formed the SPE. SPE's are often used where project financing is employed. In such instances, the SPE will usually be required to enter into financial covenants whereby it may be in default of its financing agreements if it does not maintain certain debt to equity and coverage (working capital) ratios.

5. **EPC Contracts.** A significant decision in risk sharing during construction involves choosing what framework should be used for design and construction agreements. Two of the main choices involve either a construction management, multiple prime approach ("CM") or a design-build, Engineer, Procure, Construct ("EPC") approach. Both can provide fast track delivery and guaranteed maximum

pricing which are desirable for innovative financing opportunities. Variations in the importance of the risk factors of time, cost, and control over quality affect the initial contracting choice. Careful contract preparation is essential under either approach.

Design-build or EPC contracting is a project delivery process in which all of the design and construction responsibilities are placed in a single entity. The engineer and the builder typically enter into a joint venture or subcontract arrangement, and the resulting single entity contracts directly with the owner. The primary advantage of EPC contracting is the single point of responsibility for all aspects of design, procurement and construction on a project. The designer-builder takes responsibility for completing the project in accordance with the owner's time and budget requirements. It also guarantees that the project will perform as designed. When problems arise on a design-build project, the owner is not faced with the prospect of sorting out who is at fault -- the engineer, the construction manager or one of numerous prime contractors.

IV. STRATEGIES FOR REALISTIC RISK ALLOCATION

1. **Design and Construction Contracts - Overview.** Various contractual and extra-contractual vehicles have been devised to attempt to allocate construction risks during the construction period. Contractual provisions such as "changes," "differing site conditions," "suspension of work," "variations in estimated quantities" clauses may be used to place responsibility on one or another party. "Force majeure" clauses may absolve all parties for circumstances beyond their control. "Disputes" clauses may be used to mandate continued performance in the event of a disagreement between the owner and contractor. "Termination" and "Default" clauses may identify the circumstances under which one or both parties may cease performance, and the parties' obligations upon cessation.

   The contractor may be required to guarantee performance under the contract and warrant the work done, including passing on standard equipment manufacturer warranties. In the event that completion of the project is delayed, or the performance of the completed project is deficient, the contractor may become liable for liquidated damages, i.e., a payment owed by the contractor to the owner for each day that the project is late or deficient. The contractor may attempt to cover such liability through efficacy insurance. A lender may require "delay in opening" insurance as a rider to the contractor's builder's risk insurance.

   The contract may also specify that one party will indemnify the other for losses incurred under certain circumstances. The contractor will be required to indemnify the owner for the results of the contractor's own negligence, and in some instances, for the parties' shared negligence. The owner should be required to indemnify the contractor for any hazardous waste liability. Both parties will seek to limit their indemnification so as to make it insurable, and in the case of the contractor, able to be flowed down to any subcontractors.

The contractor may also be required to guarantee that the plant will pass certain performance tests (e.g, efficiency, capacity, and reliability) and perform to specific levels, e.g., kilowatt output. This is especially the case where there is one EPC contractor responsible for both design and construction. Failure to meet contractual performance standards may constitute default. In order to protect the contractor in the event that minimum, but not all, performance parameters are met, the agreement may include "buy-down" provisions whereby liquidated damages cease and the contract price is reduced (and not avoided completely) to compensate the owner for the performance shortfall.

2. **Governmental Risk Management.** Although particularly difficult to manage, political risk may be addressed through insurance (private and public/quasi-public such as that offered by the Overseas Private Investment Corporation), government guarantees, the involvement of local government or local investors, contractors, and suppliers in the project, or the involvement of multilateral organizations such as the World Bank. Currency problems may be addressed through indexing, designation of a particular hard currency as payment, and offshore escrow accounts. Governmental risk may also include the relative stability of the host country's laws and commercial practices. This risk may be mitigated through neutral arbitration (under the International Chamber of Commerce) and choice of law provisions.

3. **Drafting Schedule Provisions.** Frequently in project financed jobs, a power purchase agreement will determine the time of completion when power must be delivered. In order to insure that delivery date, the construction contract will have a "mechanical completion" date and a "substantial completion" date spelled out in detail. The mechanical date is the date when the project and its components are completed in accordance with the plans and specifications and are ready to begin performance testing. It is important to define exactly what this completion does and does not require such as painting, documentation and other incidental activities not necessary for performance testing. The substantial completion date should also be carefully defined but generally will include successful completion of performance testing and other requirements of the power purchase agreement.

   Scheduling provisions of the contract must contain language requiring that time extensions will only be given if an excusable delay occurs which extends the critical path (completion date) of the project schedule. The contract should also require that a sophisticated scheduling program, such as Primavera, be used and updated at least monthly as a way to control the risk for everyone's benefit. Finally, the use of milestone and liquidated damages should be considered to clearly identify progress and the relative exposure of the parties for delay.

Risk shifting, exculpatory clauses for delays are generally not favored by the courts and usually are strictly construed. Provisions need to be drafted very carefully with explicit listings of the type of delays which are excusable and those for which no money damages will be payable. The emphasis should be to place the risk of delay on the party best able to control it. An equitable approach is to provide additional time for specific enumerated delays beyond the control of the contractor, but to allow only reasonable direct job site costs for compensable delay events.

4. **Allocating Delay Risks.** There are normally three categories of delays in construction contracts: 1) excusable, non-compensable, 2) excusable, compensable and 3) non-excusable. The scheduling clause should define and identify the delay categories.

Excusable, Non-Compensable. These include such things as acts of God, war, trade embargo, unusually severe weather conditions and similar delays, which neither party can control. Therefore, a party would get an extension of time in which to perform its contract. The delayed party would have no liability for liquidated damages but also no entitlement to additional costs which it may have incurred because of the delay.

Excusable, Compensable. These are delays to one party caused by factors within the control of the other party, such as the owner being unable to provide access to the site or work space at an existing plant site, when it was scheduled, thereby delaying the contractor's performance. To the extent these types of delays have caused the contractor additional time to complete as well as cost, he may be entitled to both time and costs.

Non-Excusable. These are delays within the control of the party being delayed. For a contractor such things as lack of skilled or sufficient workmen, equipment delivery delays, or simply slow performance by subcontractors would be included. With such delays, the contractor must accelerate and still complete on time or be liable to the owner for liquidated or actual damages.

An area of frequent delay contention in EPC contracts is the issue of strikes and labor disputes. This is especially important when dealing with a major equipment supplier. A realistic method to allocate this risk might be to have the contractor assume all risks for labor disputes on site where presumably the contractor is in control. Labor disturbances which affect much more than the single project might be identified as excusable but non-compensable.

5. **Accounting for Environmental Hazards.** Realistic risk allocation recently has been accepted in the industry for hazardous conditions encountered during construction. Project financed power projects have a distinct advantage in that lenders to these projects always require that an environmental site assessment be performed in the planning stages of the project. Therefore, the bidders will have available fairly thorough information on any discovered preexisting hazardous conditions.

The contract can include either remediation of known hazardous conditions as part of the work or anticipate that the owner will undertake all required remediation of the project site for preexisting hazardous conditions. The better practice in risk allocation is that the owner take responsibility for the condition of the site since the contractor is not hired principally for that purpose. The contract should treat hazardous conditions otherwise encountered during construction in the same manner as public policy treats ultra hazardous activities: whoever brought the hazardous materials to the site should be strictly liable for them. Thus if lead paint, asbestos, PCB or other such materials are brought to the site by the contractor, it remains responsible for any handling and disposal.

6. **Limitations of Liability.** Limitation of liability provisions are quite common in EPC contracting and are a good method for all parties to allocate and quantify risks. The contractor's "cap" applied on power projects can typically range from 30% to 100% of the contract value. However, specific exclusions from these overall liability caps also are carved out which can include: patent indemnity, gross negligence or willful misconduct, and indemnity for third party claims. Limitation of liability clauses also typically include statements that neither party will be liable for consequential damages. In some limitation of liability clauses, a contractor who has subcontracted design work to an engineer will seek to limit its liability for design errors to the engineer's E&O policy coverage.

7. **Use of Liquidated Damages.** Liquidated damages (LD's) may be used as a way to allocate and to quantify risks. LD's may be based on ownership costs (construction debt and service payments) or anticipated revenue loss. Liquidated damages may be reduced pursuant to a "net cash flow" clause that covers the situation where the plant is operating and generating some revenue, but the performance tests have not been met yet. The imposition of liquidated damages may also be subject to an aggregate cap, usually a percentage of the contract amount, or there may be separate caps for delay and performance LD's. There may be a buy-down amount whereby the owner can reduce the contract price to reflect a performance shortfall. Generally, EPC contracts require very specific guarantees with respect to schedule, plant output and performance. These performance guarantees can obviously cover a variety of measurements including heat rate, operability, emissions, noise, reliability and capacity factor. These guarantees are tied to liquidated damage (LD) amounts which are dependent on the specific project conditions and the power sales agreement. The individual guarantees can be capped either individually, as a whole, or by using a combination of caps. Overall, the combined caps for LD's can range from 10% to 40% of the contract amount. The World Bank generally requires minimum caps of 10% on delay related LDs and 10% on performance LDs with a combined cap of 15%. Their philosophy is to keep the cap low enough so that they will not receive "deviations" in their proposals. The World Bank limits also vary upwards and the amounts stated above would appear to be minimums in the market.

8. **Bonds and Other Forms of Security.** Payment and performance bonding which frequently are required on domestic projects, are not the common or accepted practices in the international market. Rather, the accepted practice calls for bank guarantees or letters

of credit. The international buyers are somewhat skeptical of the type of defenses and time requirements associated with traditional performance bonds.

Bank guarantees and unconditional letters of credit are typically required for 10% of the contract amount and sometimes up to 25%. Again, every country is likely to be different and may also have varying licensing restrictions concerning what entities can provide such guarantees. Also, if the parent company is substantial, a corporate guarantee may be used as an alternative form of security.

9. **Addressing Force Majeure.** In the event that either party is rendered unable, by reason of an event of Force Majeure, to perform, wholly or in part, any obligation or commitment set forth in the Agreement, then, the obligations of both parties should be suspended to the extent and for the period of such Force Majeure condition. This forgiveness period is usually limited to: (a) the suspension of performance of no greater scope and of no longer duration than is required by the Force Majeure, and (b) the party whose performance is being excused shall use its reasonable efforts to perform its obligations hereunder and use its reasonable efforts to remedy its inability to perform. Often a Force Majeure event will not excuse either party from making payments to the other party for obligations incurred before the Force Majeure event. If a Force Majeure continues for an extended period, of say more than six (6) consecutive months, either Party may terminate the Agreement upon additional prior written notice.

10. **Project Insurance Coverage.** An Owner-Controlled Insurance Program (OCIP), sometimes referred to as a "wrap-up", is a centralized and coordinated insurance, loss prevention and claims management program that provides coverage for job site construction risks for all participating parties. If the project is large enough to justify such a program, the results can include large cost savings as well as significant risk reduction and reduced potential for conflicts. There are several benefits in utilizing a wrap-up. Of particular importance, is that projects include a single, coordinated safety program which is extremely important on power projects. Safety is the single most important component of any wrap-up program. Strict adherence to a well implemented single, defined safety program will prevent accidents, improve efficiency, and encourage high morale; all of which will result in savings to all participants and help create a team atmosphere. Project insurance policies can also minimize the potential for inter-contractor (or inter-insurance carrier) lawsuits. Since all contractors are covered by the same insurance carrier, the incentive for inter-contractor suits or disputes among the various subcontractors' insurers is diminished.

11. **Securing Project Risks for Financing Purposes.** A plan for financing during each project stage will often minimize overall costs by better risk assessment and allocation. Each stage can be tailored individually to the unique interests of different types of investors, including export credit agencies, multilaterals, investment banks, capital markets and other providers of financial support. A finance risk checklist is summarized at Figure No. 4.

- **Power Purchase Agreements**

One technique used to mitigate market risk is a "power purchase agreement" whereby before construction of the plant, the customer agrees to purchase the plant's output at a price and quantity that justifies the construction and continued operation. A power purchase agreement is typically done on a "take or pay" basis; the buyer agrees to purchase a defined output even if not used. This "capacity" payment is intended to cover the costs of project development, financing, and construction, as well as fixed O&M and fuel costs (pipelines, etc.). If, however, the plant's production does not meet the agreed purchase levels, the customer has no obligation to buy. Similarly, the buyer's obligations may be capped. The buyer's obligations under a power purchase agreement may be contingent on construction being completed by a specified date, design approvals, and execution of fuel supply contracts. The producer and lenders may seek payment guarantees such as letters of credit or escrow accounts.

- **Merchant Power Projects**

Merchant power plants can best be described by what they lack -- a long-term power purchase agreement. As more restructuring and deregulation occurs in the industry, more and more projects will be built on speculation. The financing risk is that these plants will be able to produce power at competitive rates in the new open access, market-based system. Spot market sales to power marketers and shorter term duration contracts will be the source for the developers' return on investments. Banks and investors are financing these plants on an increasing basis, but with various innovative ways of securing their risks. Securitization, mezzanine financing, asset pooling are new forms of financial instruments and structures that will help manage the higher level of financial and market risk in the new age of electricity generation and sales.

Finance Risk Checklist

- •A workable in-country political, legal and economic system exists
- •Demonstrated host government commitment.
- •Risks must be allocated appropriately.
- •The cost, availability and quality of the fuel for the project is assured.
- •A market exists for the energy/products produced.
- •Underestimated technology is not involved.
- •Contractual agreements are manageable.
- •Project has value as collateral.
- •Adequate insurance coverage is available.
- •*Force Majeure* risk can been adequately addressed.
- •Initial estimates of project returns are adequate for all parties.
- •Environmental risks are manageable.

Figure 4

V. MITIGATING RISK THROUGH EFFECTIVE DISPUTE RESOLUTION

The dispute resolution procedures of the past relied too heavily on the "adversarial" processes such as litigation or binding arbitration. To be successful on projects in the future, greater emphasis must be given to "collaborative" processes for resolving disputes. The collaborative process relies on the parties working out the solution to their problems, sometimes with outside assistance. What follows is a brief discussion of some collaborative dispute resolution methods that should be considered in setting up the project.

1. **Partnering.** Team building on projects creates mutual trust and respect for the various roles necessary for a project and thereby reduces conflicts. One formalized team building concept currently being promoted, and, which has achieved positive results is called "Partnering". While contracts establish "legal" relationships, the Partnering process attempts to establish "working" relationships through a mutually-developed, formal strategy of commitment and communication. Partnering creates an atmosphere that avoids disputes.

   When Partnering is used, a Partnering workshop is conducted in the early stages of the contract for the purpose of establishing and implementing the key elements of Partnering. These key elements include: (1) commitment from top management, (2) a sense of equity by developing win/win thinking, (3) trust among the parties, and (4) the development of mutual goals and objectives.

Although the elements appear self evident, unless these concepts are specifically addressed at the outset of and during a project, the adversarial and punitive ways of the past will creep back into the relationship.

The Partnering process continues throughout the project and continues to address problems head on and early on. Partnering's intent is not to throw the contract or the specifications "out the window", but rather to promote early and cost effective resolution of conflicts involving the contract or the specifications. Partnering can benefit the project during all stages of project finance.

2. **Multi-Step Dispute Resolution Systems.** As important as the effort to realistically allocate risk up-front, is the need to design a system in the contract for early and collaborative resolution of disputes. This system should foster resolution at the lowest level possible with some form of "pressure relief valve" if the project staff is unable to resolve matters quickly. One such system includes a multi-stepped negotiation process, followed by mediation.

   Another effective pressure relief system is the Disputes Review Board (DRB). The DRB concept is a non-binding dispute "review" process by a neutral panel of experts who give opinions on disputes as they arise. The concept is promoted by the American Society of Civil Engineers and others concerned with minimizing the cost and delay of litigation.

3. **Disputes Review Board**. The DRB is made up of three impartial, informed experts in the type of construction at issue. Board members are selected at the outset of construction and sit for the duration of the project. The DRB renders non-binding opinions on disputes as they occur and provides a basis for the parties to amicably resolve the dispute. A further incentive for resolution is that the DRB opinions are typically permitted to be introduced into evidence if litigation is ultimately initiated. Each party to the contract selects a Board member and those two members select the third member. Typically, the Board visits the project periodically to observe progress in addition to hearing any disputes, which might have ripened for review. This real time knowledge of the project's progress provides the Board with an understanding that is nearly impossible to recreate in the post completion context of an arbitration or litigation.

   The principal function of the DRB is to modify behavior, not to resolve disputes. The most successful Boards have few disputes which ever formally reach the Board. Practice has shown that the mere existence of Boards provides incentive for the parties to get issues resolved without submitting disputes. Still, the Board meets at the job site, normally quarterly, and is updated on progress and walks the project to keep abreast of what is happening. The key to the Board's success is the parties' trust in the Board's competence and relative impartiality.

4. **Mediation**. Described as the "sleeping giant" of alternative dispute resolution in the early 1980's, mediation has awakened and is quickly increasing in acceptance. Mediation is private, non-binding, confidential and is concluded expeditiously. Failure is the exception. With the assistance of a skilled mediator, parties have succeeded in bridging wide gaps in positions and often in developing creative, mutually advantageous business solutions. The American Arbitration Association reports that of all cases referred to it for mediation, at least 80% settle. Within the last few years, mediation has been recommended for use in more of the standard form agreements and is likely to increase in use.

The parties to a dispute agree to bring in a neutral third party to assist in finding a mutually acceptable resolution. The mediator's only role is to guide the parties towards settlement. No authority is granting the mediator to render a binding or a non-binding decision on the merits. Rather, the mediator serves to schedule and structure negotiations, acts as a catalyst between the parties, and serves as an assessor - but not a judge - of the positions taken by the parties during the course of negotiations.

With the parties' consent, the mediator may take on additional functions such as proposing solutions to the problem. Nevertheless, as in traditional negotiation, the parties retain the power to resolve the issues through an informal, voluntary process, in order to reach a mutually acceptable agreement. Having agreed to a mediated settlement, parties can then make the results binding.

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PANEL SESSION 4

Issue 4: New Markets for CCTs

Opportunities for Clean Coal Technologies in Distributed Power Applications

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Sixth Clean Coal Technology Conference

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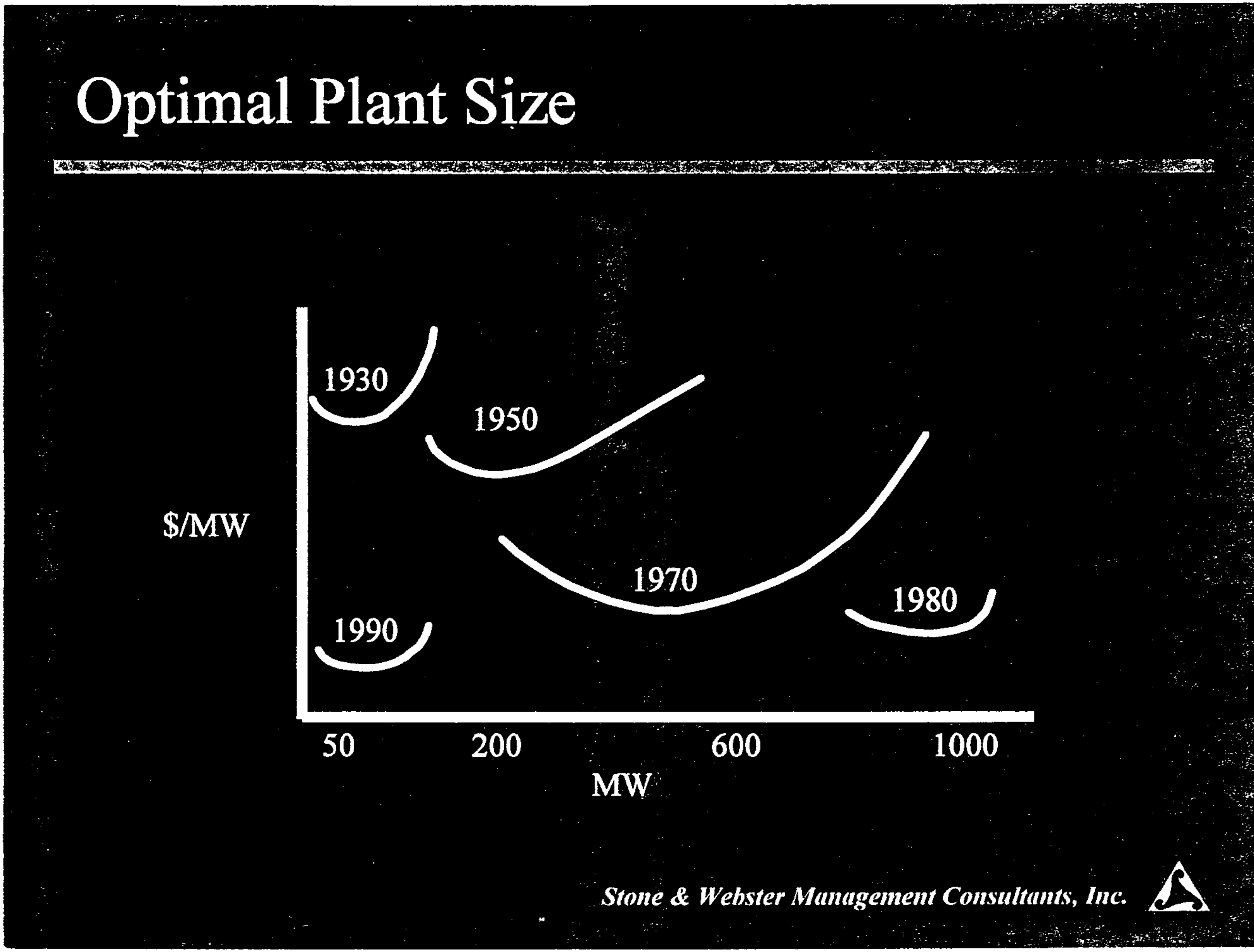
Stone & Webster Management Consultants, Inc.

Electric Industry Development -- Background

1. Strong Growth in Demand
2. Technological Advance / Economies of Scale
3. Declining Unit Cost
4. Financial Prosperity
5. Integrated Generation / Transmission / Distribution

Electric Industry -- At Present

1. Slow (or Declining) Demand Growth
2. Severe Environmental Restrictions
3. Economy of Scale Reversal
4. Independent Power Development
5. Financial Difficulties
6. FERC Order 888 -- Wholesale Wheeling
7. State Initiatives on Retail Wheeling


Optimal Plant Size
$/MW
1930
1950
1970
1980
1990
50
200
600
1000
MW
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Distributed Generation is

- power provided close to users
- small scale, 500 kW - 25 MW
- may or may not be grid connected
- commercial today

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Commercial Distributed Generation Technologies

- Internal combustion engine/generator
- Small combustion turbine
- Photovoltaics
- Wind energy system
- Fuel cells

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Internal Combustion Engine/Generator

- High, Medium, Low speed
- Fuels
- Emergency, Standby, Prime Mover Applications
- 50 kW - 5 MW
- Competitive Suppliers

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Small Combustion Turbine

- Frame, Industrial, Aeroderivative designs
- Fuels
- 500 kW - 25 MW
- Competitive suppliers

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Fuel Cells

- Phosphoric Acid
  Molten Carbonate
  Solid Oxide
- Hydrogen rich fuel
- 500 kW - 25 MW
- PAFC: Onsi
- MCFC: Energy Research Corp & M-C Power Corp
- SOFC: Westinghouse Electric

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Summary of Distributed Generation Technologies

	Capacity Range	Efficiency	Capital Cost ($/kW)
Engine Generator	50 kW - 5 MW	35%	200 - 350
Turbine Generator	500 kW - 25 MW	29 - 42%	450 - 870
Photovoltaic	1 kW - 1 MW	6 - 19%	6,600
Wind Turbine	10 kW - 1 MW	25%	1,000
Fuel Cells	200 kW - 2 MW	40 - 57%	3,750

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Distributed Power Generation

Advantages

1. Modular / Mobile
2. Relatively Efficient
3. Clean
4. Reliable / Reliability
5. Transmission / Distribution Cost Savings
6. Technology Advancing
7. Many Market Participants
8. "Under the Radar"

Market for Distributed Generation (1996-2010)

Generating Additions		
Electric Utilities	81	GW
Non-Utilities	43	GW
Cogenerators	51	GW
Total Additions	175	GW
Distributed Generation		
20% of 175	35	GW
Renewable Sources	9	GW
Potential Gas-Fired DG	26	GW
Natural Gas for DG (Year 2010)	1.9 - 2.4	Tcf/Yr
Market for DG technologies	$13 - 26	Billion

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Environmental Issues

Favors Implementation

- Small Footprint; Modular Technologies
- Reduced Emissions

Remaining Challenges

- Siting & Permitting
- Clean Air Act & CAA Amendments
- Closer to users; NIMBY

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Economic Issues

Favors Implementation

- Power production close to users
- Deferral of T&D upgrades
- Reduced transmission losses
- Incremental capacity additions
- Shorter lead times
- Mass production of units
- Natural Gas

Remaining Challenges

- High initial costs
- Customer satisfaction
- Wheeling

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Technology & Technical Issues

Favors Implementation

- Economies of scale fully exploited
- Efficiency improvements in power generation
- Improvement in emissions reductions

Remaining Challenges

- Grid interconnection
- Planning, Dispatch & Control Tools
- Demonstration of near commercial technologies

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Challenges for Clean Coal Technologies in Distributed Power Applications

- Cost versus Alternative Fuels
- Siting / Environmental
- Optimal Scale
- Developer / User Acceptance

Possible Advantages for Clean Coal Technologies in Distributed Power Applications

- Coal Availability
- Fuel Supply Security
- Long Term Contracting
- Optimal Size in Market Growth

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Upgrading Syngas to Higher Value Products
Is Syngas too Valuable to Burn?

DOE Clean Coal Technology Conference

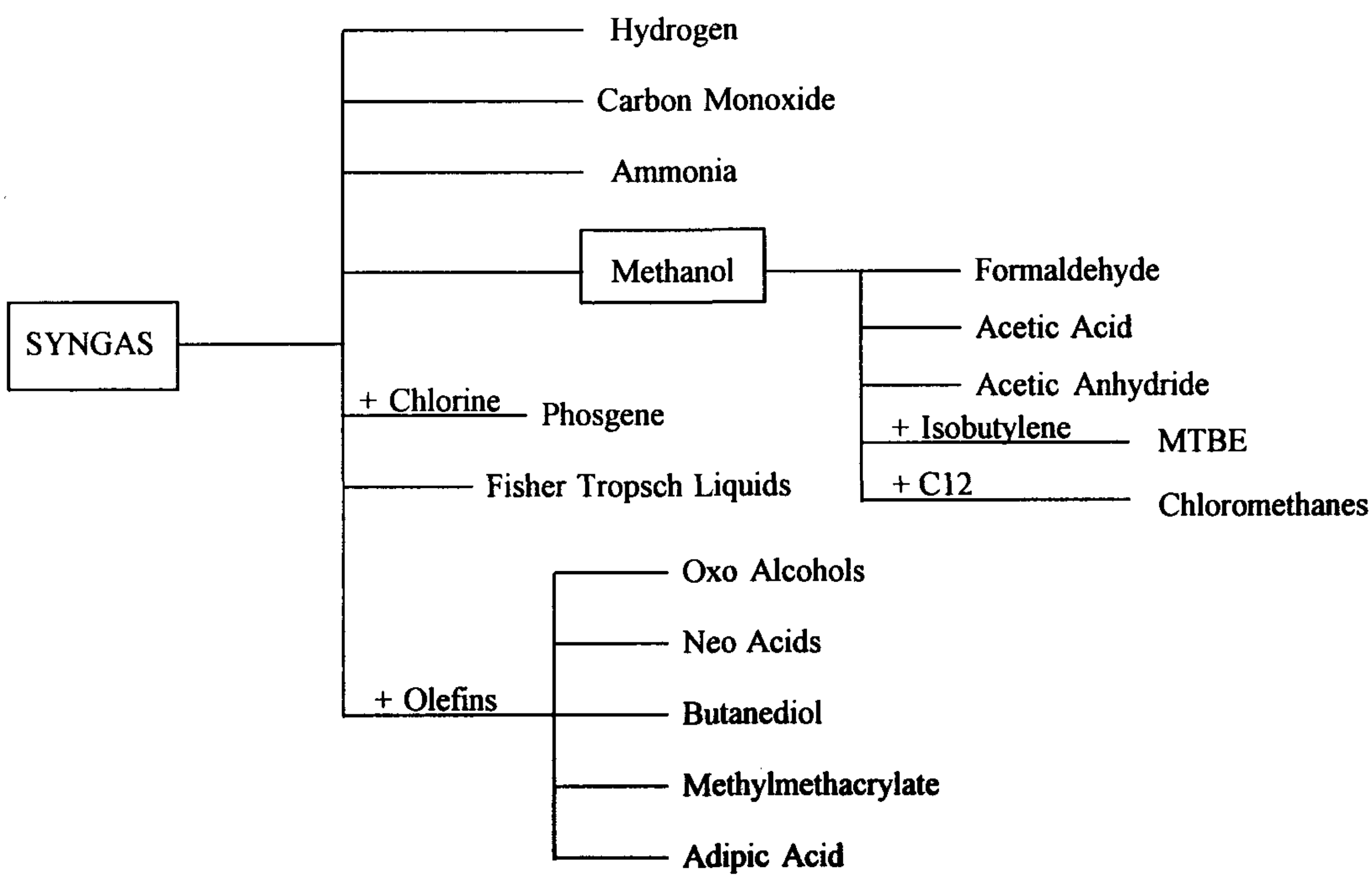
April 30, 1998

Frank Mittricker
Exxon Chemicals

Is Power the best use for Syngas from Low Value Feedstocks?

- Commercialization of IGCC has developed technology to produce power from low valued feedstocks
  - + Plants are currently operating or under construction to gasify coal, heavy petroleum liquids and petroleum coke
  - + Development of projects without government subsidies increasing
- Use of low value feedstocks for chemical production also commercially proven
  - + Ube gasifies coal and petroleum coke to produce ammonia
  - + Eastman gasifies coal for methanol and acetic acid production
- What is the best use of syngas produced from low valued feedstocks?
  - + Unfortunately, no general answer is possible
  - + Solution is site and project specific

Potential Syngas Upgrades



Syngas Cleanup Requirements

- Impurities in low value feedstocks require additional cleanup
  - + Sulfur in feed produces H2S and COS
  - + Nitrogen in feed produces NH4 and HCN as well as elemental N2
  - + Metals in feed produce metal carbonyls
- Types of sulfur removal processes
  - + Chemical absorption easily removes H2S but not COS
  - + COS hydrolysis can convert this compound to H2S
  - + Physical absorption can remove H2S and COS to low levels
- Processes to remove HCN and NH4
  - + Ammonia can be easily removed with a water wash
  - + HCN can be converted to NH4 with a catalysis
  - + Chemical and physical absorption can also be designed to remove HCN
- CO2 removal is required for chemical applications

Varying Syngas Composition

- Hydrogen content can be increased with water gas shift
  - Additional steam in gasifier will produce syngas with higher H_2 content
  - For large composition changes shift facilities are required
- Membrane or cryogenic separation required for producing higher CO composition
  - Membranes can only increase CO concentrations
  - Cryogenic separation can also produce pure products
- Removal of nitrogen is normally not cost effective
  - Would require cryogenic separation
  - Boiling point is very close to that of CO
  - Normally has relatively small effect on product quality
  - Could limit feed flexibility in some cases
- Oxygen impurities can be limited by use of high purity O_2

Important Factors in Justifying Syngas Upgrades

- Value of the feedstock
  - \+ More purification investment can be justified by lower cost feedstocks
  - \+ High carbon feedstocks tend to produce more CO
- Economies of scale are important
  - \+ Larger syngas productions reduce the unit cost of purification
  - \+ Composition variations with inexpensive membrane system more likely
  - \+ Unit costs for handling by-product dispositions decrease with size
- Market is readily available for products produced
  - \+ Minimizes transportation costs
  - \+ Synergies with existing processes or adjacent industries
- Alternative production costs are significantly higher
  - \+ Steam reforming of natural gas
  - \+ Gasification of natural gas

Is Co-production the best Solution?

- Normally requires larger investment but can improve equipment utilization
  - + Most power companies are requiring turndown during off-peak periods
  - + Using alternative gas turbine fuel, like interruptable natural gas, can free up syngas during peak period and make syngas available for other uses
- Ideally would like to recover high value molecules instead of burning them
  - + CO is an expense molecule to produce
  - + Recovery and purification costs can be expensive
- Power can be the outlet for the remaining syngas
  - + Least stringent product specification is gas turbine fuel
  - + Gas turbine can provide a flywheel for volume and composition changes

Summary

- Economical analysis required to determine potential for syngas upgrades
- The important varibales are:
  - + Readily available market for the products
  - + Syngas clean-up costs
  - + Cost of syngas compositional changes (if required)
  - + Alternative production costs
  - + Synergies possible with co-production

THE OPPORTUNITIES AND CHALLENGES FOR CLEAN COAL TECHNOLOGIES FOR INDEPENDENT POWER PRODUCERS

Michael J. Mudd
Manager, Industrial Project Development
AEP Resources, Inc.
Columbus, Ohio, USA

ABSTRACT

As Clean Coal Technologies continue along the path of maturation, it is critical that the industry understands and analyzes the potential markets that Clean Coal Technologies will serve. With restructuring of the electric utility industry the traditional role of utility generation is expected to be supplanted by Independent Power Producers or other entities who are not necessarily vertically integrated with the transmission and distribution entities as in the past.

This fundamental change in the electric utility industry will present both opportunities and challenges for the construction of all new generation, including Clean Coal Technologies. This presentation will identify and discuss opportunities and challenges for Clean Coal Technology within the structure of Independent Power Producers.

CURRENT FACTORS

I would like to start out by looking at factors, which impact the electricity supply business at the present time:

1. Our nation's installed electric generating capacity is about 750 GW. Of that capacity, 49% is coal fired. At the same time, 56% of the generation comes from coal.

2. Much of the existing capacity in the United States is currently under utilized. In 1995, the average capacity factor of the total installed capacity in the electric utility sector was less than 50%.

3. Restructuring of the electric utility industry continues to dominate the time and attention of many utility industry leaders.

4. There is a growing trend towards decoupling of generation (the production of electricity) from transmission and distribution (the delivery of electricity to the end user).

IMPACTS ON THE FUTURE

With these factors in mind, I would now like to provide you with my beliefs about the impacts of the above factors on the future:

1. The projected demand for electricity is expected to grow at an average annual rate of less that 1.5% through the year 2020.

2. Most of the new demand is expected to be able met by better utilization of the existing fleet of power plants.

3. However, there will be the need for intermediate and peaking capacity in certain niche markets in the United States, especially where there are transmission constraints. Gas turbines will be the technology of choice in providing intermediate and peaking capacity due to their low capital cost and the general abundance of natural gas at a considerably lower price, at least through the year 2005.

4. IPPs will be the primary builders, owners, and operators of new capacity additions domestically. Projected revenues will drive investment decisions in new capacity from a power plant. Financial considerations will predominate over technology decisions. Competition among technology choices will be intense and driven by profit/loss considerations.

5. IPPs will view the elements that make up the electric industry as commodities. Electricity will be viewed as a commodity. Power plant technology will be viewed as a commodity.

OPPORTUNITIES

Based on the above considerations, what will drive an IPP to select a Clean Coal Technology over other options when making an investment decision for new power generation? It will obviously be difficult for CCTs to penetrate the marketplace based on the above factors. However, I would like to offer some thoughts on key issues.

Technology Issues
Some CCTs are proven and commercially available. The most noteworthy is Circulating Fluid Bed (CFB) technology. CFB Plants are offered at competitive prices, with traditional guarantees, and are accepted by customers and financial institutions as "financeable" technology. This statement is not meant to imply that there is no need to continue to develop or improve CFB technology, but rather to say that there are designs available at reasonably large sizes (200 MW or greater) which can be offered with the full gambit of commercial guarantees and warranties which would be required for acceptable financing by lending institutions.

Others, such as PFBC and IGCC are moving closer to commercial acceptance each day. The operating IGCC plants, which owe their existence to a great part to the Department of Energy's Clean Coal Technology Program, are providing the operating experience and data required to commercialize that technology and to reduce the risk factor to an acceptable level. PFBC technology, which was proven in the United States through AEP's Tidd Plant, one of the very early DOE CCT projects, continues to be proven through the operating plants in Europe and Asia, and is expected to be fully commercialized through the successful operation of the plants currently under construction in Germany and Japan, as well as the planned CCT project in Lakeland. IGCC technology is being proven through the Sierra Pacific, Wabash River, and the Tampa Electric Projects, as well as projects in Europe.

It is hoped that the analytical tools available to engineers today, focused R&D programs to solve more complex issues, and an open exchange of information, facilitated by the Department of Energy at conferences such as this, will enable suppliers and users alike to quickly identify and resolve design deficiencies associated with new technologies. If this can happen, technologies can move through the debugging stage quickly, and bringing CCTs to an acceptable level of risk in the very short term.

Cost Issues
Currently, Clean Coal Technologies, in general, have higher capital costs than competing technologies. That is because of the higher first-of-a-kind cost associated with a not-yet-mature technology.

It is important to recognize that technical maturity and cost maturity, while related, are separate issues. Cost maturity cannot be reached until technical maturity is achieved. As long as there are real or perceived technical risks, the capital costs will be inherently higher due to higher risk dollars and the costs associated with project and schedule uncertainties. Once technical maturity is achieved, a technology must still be replicated several times to achieve cost maturity which is achieved by duplication of proven designs and the opportunities for further design optimization and value engineering.

I mentioned before that CFB Plants are being offered at reasonable sizes, and with the full gambit of commercial warranties and guarantees. Just as importantly, if not more so, they are also being offered at competitive capital costs compared to other comparable technology choices.

On the other hand, many papers for Clean Coal Technologies continue to discuss the cost of CCTs "when mature" rather than the currently available cost. This is why incentives such as the Clean Coal Technology Program are still required to assist these new technologies to overcome the first-of-a-kind cost syndrome. Acceptance of Clean Coal Technologies by the IPP marketplace mandates that they be cost competitive to alternatives. This can only happen with continued sales of emerging technologies. If opportunities for the sale of CCT plants do not exist domestically in the short term, then government and industry should work together to take advantage of the robust overseas market to get those sales.

Fuel Flexibility
The ability of CCTs to burn very low-grade fuels provides the opportunity for installation of a CCT where other technologies, such as a conventional pulverized coal-fired boiler might not be technically feasible. Once again, the ability of CFB technology to burn an alternate fuel, such as petroleum coke, effectively has allowed many projects to be built which would otherwise not be economical.

Location
Location can have a significant impact on the viability of an IPP project. Sometimes, it may be

advantageous to locate a generation source close to the user of the power to avoid or minimize the cost of wheeling the electricity (transmission cost). Other times, it may be advantageous to locate a generation source closer to the fuel source. For example, locating a gas-fired plant near a pipeline to avoid gas distribution costs, or locating a coal-fired plant near a mine to minimize transportation costs.

Power plant developers often attempt to "anchor" a generation source to an industrial steam user so that the thermodynamic advantages of cogeneration can be realized, thus reducing the cost of producing power to be sold to the grid. Features of CCTs, which may give them an edge over other options when location is a consideration include the modular construction, resulting in reduced space requirements and shortened construction time, fuel flexibility, and lower emissions, which might allow installation in environmentally sensitive areas such as near populated areas or non-attainment areas.

Output Flexibility

IGCC is clearly a key clean coal technology. Trigeneration -- the co-production of steam, electricity, and other hydrocarbon-based products from the gasification of coal is a strategic implementation of IGCC. I believe that trigeneration will be a strategic technology to an IPP who wants to arbitrage the marketplace between the commodities of steam, electricity, and other chemical feedstocks by keeping the capacity factor of several gasifier trains high and playing the market to maximize revenue from the various products.

OTHER FACTORS

In light of the above issues, there are several factors, which I believe will have the greatest impact on the successful commercialization of CCTs. Some of the following factors could be considered to be "externalities" which are beyond the control of the players in the CCT business. Regardless, if not able to be controlled, they should be understood so that CCTs can be positioned to serve the market when conditions change. Those are:

1. **Ratio of coal to gas price**: As long as natural gas price remains at a level of less than 2.5 times the cost of coal (on a $/MMBtu basis), gas technologies will dominate the electric supply sector. At the same time, it is logical to expect that such a situation is not likely to last forever. Currently, coal fuels 56% of the electricity of the United States. If all of that generation capability were to be replaced with natural gas when it is retired, the consumption of natural gas would increase by a factor of 6. Any rational economic model would predict that at the appropriate consumption point, the laws of supply and demand, coupled with required capital expenditures in the infrastructure to improve the delivery capability of natural gas, would result in significant increases in the price of natural gas.

2. **Ratio of Clean Coal Technology to gas turbine combined cycle capital cost**: This ratio goes hand in hand to the first factor. Currently, coal-based technologies require about twice the capital cost of a NGCC plant burning natural gas. Several factors ultimately come into

play in the influence of capital cost compared to the busbar power cost of a generation technology. However, the capital cost component is by far a significant factor in the overall economics.

I recently conducted an evaluation for a large cogeneration facility in North America. This facility had free petroleum coke available as a fuel, as well as inexpensive natural gas. In our analysis, on a first-year basis, an F or G class NGCC facility was the economic winner compared to a petroleum-coke fired CFB boiler if the natural gas could be procured for $1.50/MMBtu or less, even when the petroleum coke was provided at no cost. There were several other considerations, which affected the economics of this analysis, but the capital cost ratio had the largest impact on the overall economics.

3. **Ratio of efficiencies between a given CCT and the best in class NGCC plant**: This factor will have not only economic impact on the busbar power cost, but it or will also greatly impact the environmental comparison between the two technologies, most noteworthy with respect to CO_2 emissions.

4. **The market price of new-entrant base-load power**: This factor is significant because it will impact the ability to dispatch a given plant. Considering the capital cost of coal-based technologies, and even with a coal price at a level of $1/MMBtu, the first-year cost of electricity from a coal-fired plant would exceed $30/MWh. This figure compares to a current average market-clearing price much closer to $25/MWh.

5. **The perceived risk of a CCT**: Business people will have a strong voice in the final say of which "commodity" will be financed by the banks. If there is a perceived risk of a CCT, the banks will either refuse to finance the project or they will impose additional costs such as lower projected capacity factors or higher contingency costs in the economic model, which penalizes the CCT. These penalties could make the technology uneconomical compared to alternatives.

CONCLUSION

Clean Coal Technologies are intrinsically beneficial to the United States, which has such abundant coal supplies. It is of paramount importance that industry and government continue to develop and commercialize efficient, environmentally compatible, and economic technologies to allow the continued use of coal to fuel our nation's thirst for economic, but clean power.

The dynamic changes, which are occurring in the electricity business have radically altered the premises under which the original Clean Coal Technology Program was initiated. At the same time, the opportunities for the application of Clean Coal Technologies far outweighs the issues discussed today. I strongly encourage the Clean Coal Technology community to continue in this important mission to ensure that CCTs meet their expectations of clean, efficient, and economical power from coal.

CLOSING PLENARY SESSION

Clean Coal for the 21st Century:
What Will It Take?
Conclusions and Recommendations

Environmental Summary

Unprecedented Environmental Concerns

Doug Carter, USDOE

Overview

Population and Poverty vs Environment

Conventional Pollutants

Global Warming

Research Needs

Population & Poverty vs Environment

- Population doubling every 50 years (D. Todd, GE)
- GDP quadrupling every 50 years
- 25% of Africa has access to electricity (J. Butler, African Electrification Foundation)
- Energy Ministers: Foster a stronger economy for 2 billion new people or deal with consequences (R. Lawson, NMA) (5 billion by 2050)
- Prevent environmental impacts (CAA); stabilize atmospheric concentrations of GHGs (Rio).

Conventional Pollutants

- SO2 and NOX
- Title IV largely achieved in US. Major reductions in SO2 and NOX (L. Kertcher)
- Mission accomplished in EU: (G. Morrison)

	SO2	NOx	PM
Need	95	85	99
Can Do	99	95	99.9

Conventional (good news)

- All STEAG bituminous coal plants have SCR, FGD, ESP. Meet 0.14 #NOX/mmBtu, 0.33 #SO2/mmBtu. (V. Rummenhohl)
- German SCR on large plants is $52/kw.
- Phase 2 Ozone rules in NE, May 1999: 55-65% reduction, 0.2 #NOX/mmBtu floor. Scheduled to drop to 75% reduction & 0.15 #NOX/mmBtu floor in 2003.

Conventional (bad news)

- Ozone NOX reduction (SIP call) may pose problems of timing, lack of US experience, use of high-S coal (M. Geers)
- Challenge for US is meeting NOX limit of 0.15 #/mmBtu, 22 state SIP-call. (L. Kertcher)
- Cap on NOX after 2007 mandates ever better technology. (D. Carter)
- Possible requirements for SO2 to meet FPM NAAQS. (L. Kertcher)

Conventional (equity issues)

- 1970-95 regulations cost $25 billion for utilities in 18 states. 70% of burden on MW. (M. Geers)
- Half the NOX SIP call cost falls on 6 MW states
- MW impact on NE is minimal.
- Stringency and timing (3 years) of SIP call is unreasonable.
- Insufficient US experience w/SCR, high S coal.

Global Warming

- Kyoto: 5% average reduction for developed countries, vs 1990; 7% for US. (L. Kertcher)
- Biggest challenge to coal. Cinergy will have to cut coal use 50-80% to get 30% reduction. (M. Geers)
- Global Climate Coalition supports Rio FCCC, but opposes Kyoto Protocol (G. McDonald)
  - Adverse economic impact; no trading rules.
  - No developed countries; shifts CO2 from developed to developing countries.

Global Warming: Trading

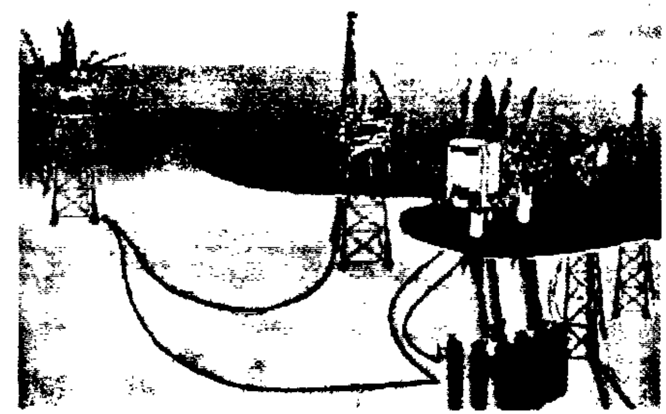
- Administration says trading could lower costs of Kyoto by over 75%. (D. South)
- US and Japan favor trading; most other nations oppose.
- Most cost-effective trading (w/ developing countries) is heavily restricted. More rules to come.
- Trading w/Russia looks attractive. EU favors restrictions - capital investment, 50% domestic

Global Warming: Long term

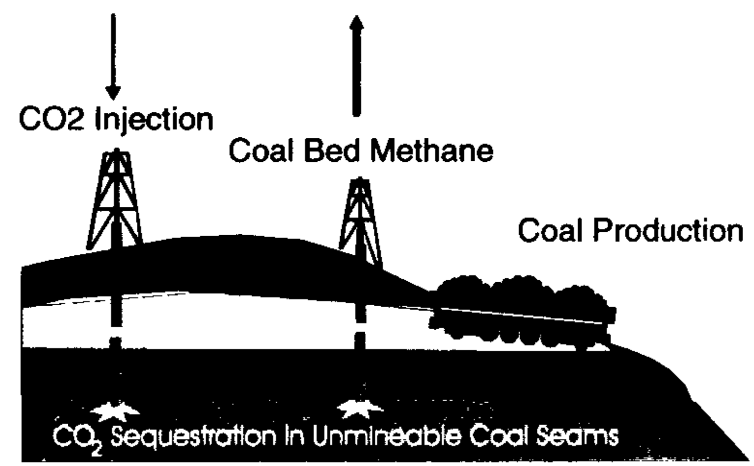
- Kyoto is first step: stabilize emissions from developed countries. (D. Carter)
- Rio FCCC goal is stabilizing atmospheric concentrations at "safe" levels
  - Implies 60-80% reduction in emissions, or offsets.
- Need to demonstrate safe & economical sequestration technologies, in case they are needed. (R. Lawson)

Practical Technology

- Sequestration is already deployed
  - Sleipner Gas production in North Sea
  - 70 Enhanced Oil Recovery sites worldwide
  - Numerous reforestation projects underway
- Generic classes
  - Capture and control
  - Enhanced sinks
  - Novel concepts (biomimicing)

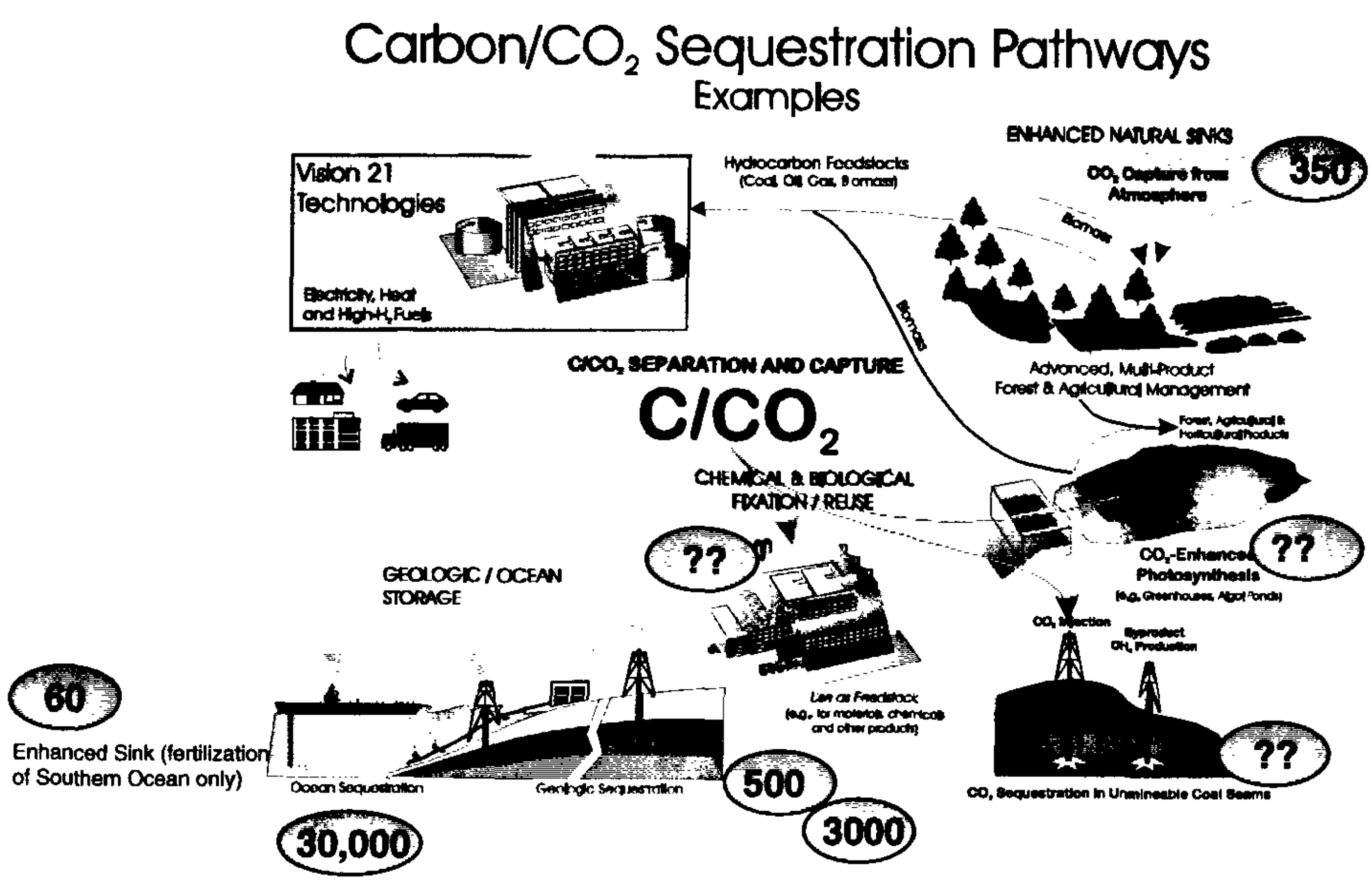


Statoil's Sleipner natural gas platform, with CO2 injection (center).



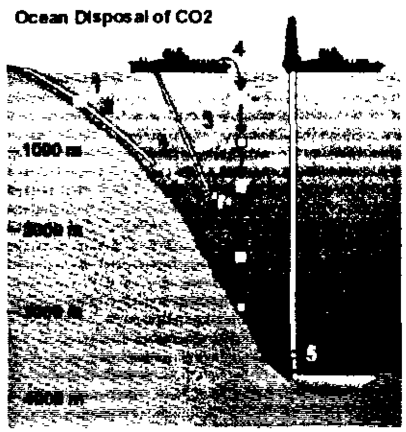
Sequestration Potential

Potential Sequestration (Billion Tons Carbon)



Sequestration Approaches: FY99 Budget Request

TRADITIONAL
~$1.0 million



Dissolution: 1 Dense Plume, 2 Droplet Plume
Dispersion: 3 Towed Pipe, 4 Dry Ice
Isolation: 5 CO2 Lake

ENHANCED SINKS
~$3.5 million

NOVEL CONCEPTS
~$4.0 million

Industry/International Collaborations
$1.5 million

Exploratory Research
$1.9 million

Research Needs

- Michael Geers
  - Waste stream reuse
  - Multi-pollutant technologies
  - Much better power generation efficiency
- Richard Lawson
  - High efficiency generation & carbon sequestration
- Larry Kertcher
  - 0.15 #NOX/mmBtu retrofits
  - Carbon sequestration

Research Needs #2

- David South
  - Flexible trading policies
- Gail McDonald
  - Better science on GCC
  - Cheaper mitigation options
  - Global involvement

DOMESTIC COMPETITIVE PRESSURES FOR CCTS

Thomas J. Grahame
Office of Planning and Environmental Analysis
U.S. Department of Energy
Washington, DC

Let me try to sum up a very, very complex session yesterday. For those of you at the periphery, who might have trouble seeing overheads, not to worry. I don't have any. What I'm going to try to do here, first, is to summarize some of the large number of uncertainties that were raised in yesterday's talks, and not just within the session on the effects of competition for CCTs, but also as Doug did, to include pertinent information from many of the other speakers was well.

Then I'd like to turn towards the smaller number of areas where there seems to be some widespread agreement and then try to piece together a few conclusions.

The uncertainties primarily affect existing coal units, not CCTs, at least on the surface and in the near term. But because they also affect the rate of introduction of new units in the short-term as well as perhaps the rate of retirement of existing units, these uncertainties will in fact affect the size of future markets for new capacity a decade or more out.

The uncertainties include, first of all, the rules regarding restructuring legislation, and the status and the level and the pace of deregulation. First in this group are new added environmental requirements. As Terri Moreland mentioned, these are driven by the perception of higher emissions under deregulation. Yet, as Gil Waldman noted, one of the things that could well happen and probably will happen under deregulation is a much larger emphasis on squeezing use out of every last Btu. Thus, we may end up with fewer emissions, not more, under deregulation. Nevertheless, given the perception of an increase in emissions, at least nine states out of approximately 16 that currently have deregulation legislation, or deregulation pushed by regulations, do have some sort of new environmental requirements. For instance, some states have required that generators must meet tighter new specific environmental requirements if their power is sold into the state under deregulation.

Secondly, there are informational requirements, which simply require that the seller list the amount of pollutants per kilowatt hour so consumers can compare emission rates of different sellers.

Minnesota, and I had not realized this, is discussing in their legislation a carbon tax that could be up to $100 a ton. The dollars raised could be used to reduce other taxes.

And perhaps most important there are proposals for renewable portfolio standards which are requirements that anybody selling into a given market must have a minimal percentage of power generated from certain non-hydro renewable sources. Such legislation normally requires that a rising percentage of renewable energy be bundled into the sales over time.

Bruce Craig of the Natural Gas Supply Association pointed out that such a requirement is a legislative determination of market share. He referred to it as both uneconomic and antithetical to the goals of deregulation. And, in fact, he noted that it is a competitive threat to both natural gas and coal.

Bruce discussed the numbers in some of the legislative proposals, with the renewables mandate rising in later years to as much as 20 percent of all sales.

There is, I think, a little bit of confusion about the renewables mandate. The confusion in my mind arises in that some proponents of renewable mandates view it as in fact just a way of doing R&D, of promoting new technologies. So it's sort of like a demonstration program in this paradigm. And none of us would disagree with the idea of demonstration programs. These are very legitimate for any new technology that has environmental promise but that's above market price until it is more fully commercialized. However, Bruce noted that renewables portfolio standards are not demonstration projects. They are not limited to particular projects. Once you have something like this in law, it generally never leaves. And generally the only way is up a steadily rising percentage of the market mandated by law. So a renewables portfolio standard is not just a different way of providing demonstrations. Instead, it may become a permanent feature of the landscape once it gets in. I think that's the message that Bruce Craig would carry to us.

One of the things that Terri brought up is that in all of the deregulation legislation, and this suggests the kind of thing Doug was talking about earlier, there's no mention of coal's positive economic role in any of the restructuring legislation. The term coal is barely mentioned. The economics are barely mentioned, and so as Terri suggested, perhaps deregulation legislation at the state level may be an opportunity to discuss the positive economic role that coal provides.

There are a number of other areas where there is uncertainty in deregulation legislation. There are things like exit fees, the level of stranded cost recovery, reliability requirements, and the pricing of ancillary services such as backup power that again, as Gil Waldman mentioned, can in fact, obstruct full competition under deregulation.

And they all will have an effect on how competitive the market will be. Gil Waldman gave me an example after his talk. In Illinois, after the legislature passed restructuring legislation and put in exit fees, Gil's company, Trigen, had a highly economic project where they were going to cogenerate, and produce high power and heat, and perhaps chilled water as well. They were going to squeeze the use out of every Btu at an industrial site. This, of course, would mean the industrial site would no longer be buying much electricity from the local incumbent. But, the legislation has an exit fee requirement which means that if you decide on economic grounds that you don't want to buy any more electricity, because you are now cogenerating, you still have to pay the incumbent utility for not buying from it anymore. This exit fee didn't exist before the deregulation legislation And that destroys the economics of the project. So this is the kind of uncertainty in many states that could in fact inhibit good competition.

Mr. Waldman also pointed out that in a competitive market, with one of the trigeneration applications that his company promotes, in some cases they can use up to 90 percent of the Btus in the fuel, compared to about 35% in a conventional plant and about 50-60% in many cogeneration applications. Gil put up a graphic which suggested that in one of his highly efficient trigeneration applications the price of electricity sold from such an application, after you've basically used all these Btus and gotten paid for the chilled water and everything else that you're producing, the price of electricity could in fact, in his judgment, beat a price of electricity from a standard, large coal plant with total fuel and O and M costs of around two cents kilowatt hour plus a nominal transportation cost.

And I think we ought to think real hard about this. This is probably going to be the main theme of my talk. Under deregulation, because of concerns about energy efficiency, environmental issues, and global warming and additionally because of economic reasons, the future for coal may well be squeezing a use out of every single Btu. And I will return to this theme a little bit later.

Finally, another uncertainty: will there, in fact, be federal legislation to harmonize the crazy quilt, the different regulations in different states, that Sharon Belanger noted in her talk? And if there is, will there be a federal portfolio standard for renewables? That's a very big uncertainty on both counts.

Turning to a different kind of uncertainty, will there be a "gold rush" of new natural gas units under deregulation? Sharon Belanger noted that in New England, there are 23 gigawatts of proposed new natural gas units. These are not commitments. Nonetheless, I think we've seen boom and bust in other parts of our economy. It wouldn't necessarily surprise me to see perhaps a little bit too much new capacity built by people that want to basically be first in the market. So I think we have to recognize there could well be a boom of new natural gas combined cycle units under some circumstances. You would think, from pure economic grounds, that in the coming era where there is no guarantee of any cost recovery, unlike the world of 15 years ago, under rate-based construction by utilities, you would think that the economic logic of this new paradigm might go against overbuilding. But we've seen boom and bust in many parts of the economy so I do not think we should discard the notion that we could see kind of a boom of new natural gas combined cycle plants.

Another uncertainty: How much spinning off of assets will there be, and what will that mean? Sharon Belanger pointed out 60 gigawatts have already been spun off from existing utilities in the U.S. Terri Moreland notes that some states that are deregulated have either required or strongly encouraged the spinning off of assets. Indeed, I think some utilities, if they believe that they don't have a competitive advantage on the generating side they probably will decide that they are going to be wires companies and they will sell their generation assets. So what happens when these assets are spun off? Will the new owners be more efficient? Will they be better at squeezing out costs, at getting more capacity and/or efficiency from these units? Will this be a boon in terms of existing units or, alternatively, some might argue that the people who are buying these assets may not be all that interested in the assets. What they may want is a site that has all the necessary water and air permits, a site where perhaps they can build several thousand megawatts of new combined cycle natural gas capacity without going through the contentions and drawn out permitting process.

Whether it goes one way or the other will have an awful lot of impact with regard to what our generating picture is going to look like ten years out when, arguably, new CCTs burning coal might start to enter the market.

Nuclear has been mentioned: how much nuclear premature retirement will we have? We have seen four units retire prematurely this year. Certainly in the future, if you need a big capital improvement at a nuclear unit, you'll not be able to go to your PUC in a deregulated market and say, "We'd like 100 million dollars." Big capital requirements could presumably cause a lot of premature nuclear retirement in the future. There are some plants, not very many, whose running costs even today may not be competitive in a deregulated market. That's a fairly large uncertainty affecting the need for new units. Another one that wasn't raised yesterday but I think it does need to be raised here is, and I'd like to thank David South for discussing this with me, is the cost of upgrading natural gas transmission capacity, if we do have a large increase in natural gas use. The work that David did for the Five Lab study suggests that there will be the need for fairly costly improvements in the natural gas transportation system. So even if the wellhead prices stay low, as several speakers think they will, for at least a decade, there are other costs involved that need to be looked at and that is again a cost uncertainty.

Climate change issues: Doug's covered them very well. And again both David South and Charles Feinstein of the World Bank discussed these issues and the only thing I would say with regards to trading is David sensitized me yesterday to the notion that even if there's really cost effective ways to offset your CO_2 emissions today, you may not be able to get credit for them. Your costs may be very low. Perhaps you can get some carbon offsets for one to two dollars a ton for CO_2, but there's a lot of questions as to whether you'll get any credit for that. And if you cannot get credit for it, why do it, even if it's really, really inexpensive? And that's very important to our technologies, both existing coal and new CCTs.

Turning to the market for transportation fuels, the challenge here could possibly turn out to be an opportunity. John Wilson noted that the military is going to reduce its fuel use per vehicle by over 50 percent by going to electric drive. And it turns out that U.S. auto makers are also investing huge amounts of money in electric drive for similar reasons. They see the need for much better fuel economy coming down the pike as well. But electric drive with regenerative braking and other ways of saving energy doesn't necessarily mean that the car is going to be powered by electric batteries. It can be powered by hybrids, fuel cells, and traditional gasoline engines. But there's going to be a big fuel market out there. And John Wilson suggested that those entities that wish to provide electricity for electric vehicles can capture part of this market. They may need to think about a partnership, perhaps with makers of batteries, new battery technologies that perhaps have great promise but need a large amount of R&D. The term he used was "skunkworks" mentality. Then he suggested that perhaps if some of these highly efficient electric cars are, in fact, commercialized, there may be some CO_2 credits available. So that's something to think about as well.

George Preston pointed out the need for flexibility in deregulated markets. Certainly flexibility is going to be very, very important. CCTs may need to be not just highly efficient but highly flexible in terms of power production. The liquid phase methanol demonstrated one way that flexibility in electric power production could work. Although it's also true that if you have a CCT that is the lowest cost producer in a region, that producer may just keep producing around the clock, but that's yet to be determined.

Kevin Kerscchen of Black & Veatch pointed out yet another uncertainty, that some existing coal plants can be retrofitted in a way that will add up to 10 percent of the capacity and increase efficiency by up to four percent. This certainly could help give some existing coal units a competitive edge, and perhaps decrease the need for new plants a little bit.

So how do we make sense of this whirlpool of pressures, and what it might mean for CCTs? I think, first of all, let's visit a couple of places where there seems to be a lot of consensus. The first is that several speakers, Sharon Belanger and George Preston among them, indicated that we have got to get down to a cost of about $800/kW before IGCCs can be competitive, at least in the traditional stand-alone way. The traditional stand-alone way is sort of the stove pipe mentality where the electric units are kind of separated from everything else and they only generate electricity. Whatever doesn't go into electricity goes into the atmosphere and is wasted as energy.

I would suggest that the $800/kW figure seems to apply to stand-alone technologies. But if Gil Waldman, Doug Carter, and the speaker from Exxon are correct, perhaps the future is not stand-alone electric technology. Perhaps the future is squeezing every last Btu. And I would suggest that, if we can do that, perhaps if we can have a Trigen Corporation for IGCCs, not for natural gas as Gil Waldman's company is for, but a Trigen Corporation for IGCCs, perhaps we don't need to meet that $800 kilowatt figure before we can start getting some success in the marketplace. It sounds like a number of refineries are going to be putting in IGCCs in the near future to squeeze every Btu out of the petroleum coke, for example.

It is not $800 a kilowatt there right now. So perhaps what we need to be thinking about is a much more holistic way of using every last Btu. If we do that, maybe we can start thinking about getting some of these technologies on line a little bit quicker.

Let me go beyond that a little bit. I'm going to editorialize a bit here. In the future world where we're going to have to have to account for every last bit of carbon, let's think about what Frank Mittricker of Exxon noted--that carbon monoxide is a very important chemical feedstock. A number of these products, and I thank Neville for our conversation on this, that use carbon monoxide as a feedstock may well end up being sequestered or recycled. In Europe, they are starting a movement to recycle car bodies, but if you go to landfills in this country, the people who study the land fills have found that the decay rate in landfills is so low that you can find a 1954 newspaper and still read it. So I would suggest that in this country where we throw away cars that have gotten to the end of their useful life, I would suggest that if a car with substantial plastic goes to a landfill we could probably count it as sequestered.

The carbon monoxide, if you account for where it goes, some of this is going to end up being sequestered. Some of it is going to be end up being reused. It may well be if we account for all this we may not have to find quite as may offsets for CO_2 as we might have, had we thought of the IGCC just as a stand-alone proposition.

Let me add one more thing. The future of the electric industry under deregulation, I think you can see what's happening right now. There's a lot of consolidation right now. If you look at any large capital intensive industry it always tends towards concentration. That's the nature of a very capital intensive industry. In the future we may see, 10 to 20 very large, highly efficient companies that produce electricity. The Duke Powers of this world, the Southern Companies, the U.S. Generating companies, and the AEPs, for example.

So it seems to me that companies that are going to have the capability and are going to arguably be dealing in many energy markets, in the future under deregulation, it seems in such a world that the future of IGCCs is going to basically be to get some of these companies to think of IGCCs the way Trigen is thinking about natural gas. That means using every last Btu, chemical feedstocks, cogeneration, and thus needing fewer CO_2 offsets.

Okay. The second issue where there's some consensus is the fact that natural gas prices are likely to remain low for at least several more years at the wellhead and perhaps well beyond that. We need to recognize that competition has done wonders for bringing down the price of wellhead natural gas wellhead prices. The technological advances are amazing.

Let me just mention that not just Frank, but Doug Todd also noted that there may be a number of IGCCs built in the coming years at refineries around the world, generating chemical feedstocks from petroleum coke. This base of experience cannot be anything but useful. It may not be exactly what we have in mind because coal won't be the feedstock. It may not be centered on coal, but if you build up a wealth of experience for vendors and others involved in IGCC production and operation, that's going to be good for IGCCs, whatever they burn.

Let me move to my conclusion now. Competition is coming in the electric industry. It won't be stopped. Gil is one of the many that's made that observation. The pace is certainly unclear. The final form is very unclear. As we can see in both natural gas and telephones, the pace is often going to be a lot longer than we think. So this could be a journey that has stops and starts and we don't really know when it's going to happen in the interim. But, I think we should count on that it will happen.

Secondly, the advantages of competition are in fact very substantial. Bruce Craig pointed out that we ran out of natural gas in the days of wellhead price controls, but now that the legislative directives of the late 1970s about fuel choices for electric generation are gone and now that the wellhead price controls are gone, and we have pretty much a decontrolled market for natural gas, gas is plentiful and prices are again low, far fewer than anyone forecast 10 or 15 years ago.

The power of the marketplace has also pushed the costs of new gas turbines way down and efficiencies way up.

Market competition has helped promote new technologies that have tripled the rate of success for finding new natural gas reserves.

Let me repeat a conversation I had with somebody from Southern Company a little over a year ago. Southern Company, for the next 15 years, pretty much all of their incremental generation is going to come from natural gas and it's going to come from the Gulf of Mexico and it's going to come five to ten years out from resources 5,000 feet under the Gulf or deeper. They will be accessed with technology that's not yet completely developed, yet the price, as far as Southern Company is concerned, as far as the vendors of the gas is concerned, is going to be about the same as today. We really should not underestimate how technology development can be driven by marketplace competition. So natural gas prices are trending lower now in real terms due to deregulation. And I think Bruce Craig's message in part is that deregulation may also provide incentives for new CCTs, as well as for a more innovative, less costly, and more efficient electricity sector.

Now, along this theme, another important conclusion is that of Bob Bessette. He expanded the theme of competition, linking the wealth of a Nation to the openness of its markets and noted that this wealth depends in part on energy costs. It would be hard to deny, in my judgment, some link between falling oil and gas costs in these recently freed markets and the prosperity of the 90's. Successful deregulation is linked to the economic vibrancies of the 90's.

In sum, retail electricity competition is coming. It's helped other technologies develop. It may well help CCTs develop. The restructuring legislation to come at state level, and especially if it comes to the federal level, must not dictate the winners and losers, Bruce Craig noted, or many of these other economic benefits may be lost. And also as Terri Moreland noted, any R&D monies that are generated as part of restructuring legislation should be distributed even-handedly as it was in Illinois between clean coal and other technologies deserving of R&D. In sum, on balance, competition has been very good for our economy and for the sectors that have been deregulated, although the results have not all been without any jacket. We can think about people in small towns with airlines for example, but the bottom line is for the country it has been very good for our economic vibrancy. We should not fear deregulation's bracing effects on the electric sector.

FINANCING CLEAN COAL TECHNOLOGIES

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Ben Yamagata began with a reminder that coal will produce about half of the U.S. generation through 2020. Growth in China and India will be amazing. He reinforced Gen. Lawson's point that poverty is the greatest polluter. Additionally, he explained the prosperity of a country is directly tied to its ability to generate electricity.

Ben said we need to spur economic growth in developing countries by providing the electrical generation needed. Coal will be the choice for some developing countries because it is the most available and the cheapest. We must provide the technology to cleanly and efficiently use the coal.

Ben reminded us of the competitive pressure of combined cycle natural gas generation and electric industry restructuring. Ben concluded by saying developing countries want generation of energy first and environmental responsibility second, which provides an opportunity for clean coal technologies to address both concurrently.

Next, Mr. Masaki Takahashi with the World Bank spoke. He discussed environmental control strategies deployed by the Bank of China. He mentioned the Pollution Prevention and Abatement Handbook and its web sight at www.esd.worldbank.org/pph/. As well as the following publications:

- The Energy and Environment Strategy (Fuel for thoughts)
- Environmental Management for Power Development (including CCT)

He then discussed the Beijing Economic Research Institute and the World Bank study called Least-Cost Strategy for Environmental Compliance in the Energy Sector, which included case and least cost studies for Shanghai and Henan, China. In Henan, 18% of the TSP emissions were from the power industry and total emissions were over 231,000 tons.

He said a significant portion of electrical generation is from small generation units of 6-50 megawatts in size. In Shanghai, much of the TSP will be eliminated by ESP and at a higher cost, using a coal washing process. Removal cost of TSP in Shanghai will be as high as 800 dollars per ton.

Mr. Masaki Takahashi discussed SO_2 emission forecasts for Shanghai. The control costs will range from 200 1600 per ton of SO_2 removed. He presented the various technologies that China will use to reduce SO_2. Costs for Henan will range from $200-1000 per ton removed.

He addressed China's NO_X emissions as well. China has over 700,000 tons of annual NO_X emissions, with the power industry responsible for approximately 42 percent.

Externalities are considered by China's power industry, which includes consideration of the external benefits as well. It was interesting to note the greatest external costs were associated with TSP while externality values for SO_2 and NO_X were significantly less.

As Rapporteur, I found it interesting that China is addressing power needs differently than the United States. While the U.S. utility industry embraces small generation to reduce marketing and financial risk, China has banned small generation other than cogeneration with environmental controls. And while our regulatory commissions have considered and rejected the externality theory, China has embraced the New York Externality Model. And again, China considers external benefits in their calculations. I hope the World Bank does as well.

Charles Feinstein of the World Bank discussed the seriousness of the Climate Challenge. He said the World Bank believes the science of the IPCC, that their clients are vulnerable and action needs to be taken.

Mr. Feinstein says Climate Change does not mean coal is going away. There are many options ranging from China replacing their under 25 megawatt power plants and household coal use to implementing clean coal technologies, which present higher operating efficiencies.

He then discussed the GEF financing process, which is available for developing countries. The World Bank provides incremental cost financing to obtain global benefits by supporting new technologies (i.e., instead of a pulverized plant proposal, the World Bank would finance an IGCC).

GEF sees IGCC as a priority option.

Mr. Feinstein discussed bilateral trading of emission reduction technologies--he used Norway and India power plant transfers as an example. He then explained the prototype carbon fund process. This was followed by potential market scenarios for climate change carbon emission reductions through trading. He summarized by stating anyone with carbon emission reduction opportunities today could find financing available currently from the World Bank as well as through General Electric.

The next speaker with Sierra Pacific Power Company reminded us to always expect surprises and the unexpected. Therefore, it is important we plan to manage and reduce risk. He focused on project risk containment. Clean coal technology projects have higher risk domestically and even higher with international projects.

Risk should be assumed and spread about the various contractors developing or building the project in addition to the risk assumed by the participation of the public through the federal matching funds.

Risks include the cost of construction, fuel, transportation, financing, operation and maintenance as well as the risk of finding a market for the generated power. He discussed hazardous condition risks, traditional contracts (which are hard to use to gain financing) and EPC contracting (which is easier to finance). Quantification and limitation of risk should be included in project contracts. Enhanced performance rewards should be included in the initial contract as well as penalties for under performance.

Insurance as a risk management tool should be considered.

In summary, risk should be assigned to the party most capable to manage the risk or to profit from properly managed risk. The best dispute resolution is the dispute avoided. However, a multi dispute resolution process should be agreed to in advance. This requires foresight of problems before the project is initiated and contracts are completed.

Due to time constraints, no questions were presented.

NEW MARKETS FOR CCTs

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I reviewed the four presentations on this subject from the perspective of the Conference's theme: "Clean Coal for the 21st Century - What Will It Take?" The four presenters addressed this question effectively as they went beyond simply describing the "New Markets for CCTs" and provided insights as to why (or why not) these new markets are attractive, and what to do in order to succeed in them.

In this panel session, in spite of the broad range of new markets covered, common threads were dominant, especially in the speakers' explicit and implicit Conclusions and Resolutions. I will here summarize briefly the topic of each presentation and the Main Issues that it raised; then I'll offer my synthesis of the Conclusions and Resolutions for the session as a whole, based on the four presentations.

Summaries and Issues

1. New Markets for CCTs

Doug Todd's Wednesday lunch address served effectively as the Keynote for our panel session. His rich content would have warranted a descriptive subtitle, say, "Lessons Learned from Marketing New Technology," and Doug personally has been through the wars. He characterized the main Issue as "Why aren't the dogs eating the dog food?" - i.e., given the obvious attractions for Clean Coal Technologies, why are the demand and the deployment rates for them still slow? He enumerated several of the common barriers that are encountered, which I paraphrase using his metaphor as follows:

- If you change the food: you may know it's better, but you may have to package it differently to convince the dog it's better.
- If it's a different dog: you shouldn't expect the same food to be attractive.
- If your kitchen is suddenly declared off limits to the dog: both you and the dog have to learn to operate under different rules for feeding it.

2. Electric Utility Competition and Distributed Generation Implications for Coal and CCTs

Joe Ramsey's contribution described the transformational changes taking place in the electricity generation business that are driving the emergence of Distributed Generation as an electric supply business sector, and he summarized the important distributed generation technologies and their applications. The main issue for Clean Coal Technologies as regards the distributed generation market is that the changes that have made distributed generation attractive as a business - e.g., shrinkage of the optimal plant size, emergence of the independent power producer sector, wholesale and retail wheeling - don't create advantages for Clean Coal Technologies and in most cases put Clean Coal Technologies at a disadvantage.

3. Upgrading Syngas to Higher Value Products - Is Syngas Too Valuable To Burn?
Frank Mittricker described in classic chemical process engineering terms and economics, a concept few of us had given much thought to - that gasifier output has a value highly dependent on its feedstock and local market conditions; and that it is conceivable that the syngas would be so valuable for upgrading to commodity chemicals that it doesn't make sense to send it to a combustion turbine for mere burning. In his presentation Frank nicely knocked down the straw man Issue that he implied in his Abstract - that integrated gasification/combined cycle on "low value hydrocarbon feeds is ... relatively difficult to justify." I would, therefore, describe the real Issue raised by Frank as: the process development and business decisions on integrated gasification/combined cycle syngas upgrading are site- and situation-specific, and there is no magic formula or criterion that can be used to judge economic feasibility.

4. The Opportunities and Challenges for Clean Coal Technologies for Independent Power Producers
Mike Mudd's offering described the nature of the independent power producer market and posed explicitly the main issue for Clean Coal Technologies - that (similar to the Distributed Generation market) it will be difficult for Clean Coal Technologies to penetrate the independent power producer market, given the existing underutilized coal plant fleet, the low capital and operating costs for Clean Coal Technology alternatives - notably natural gas/combined cycle, and the lack of technical maturity of Clean Coal Technologies which implies increased perceived risk and higher effective cost.

All of the issues I've outlined from the four panelists can be summarized as: "It's difficult to develop a new market, or penetrate an existing market you haven't been in, because ... "

Conclusions and Resolutions

Now let's look at Conclusions and Resolutions from this panel. I've synthesized three:

1. Success in any of the new markets is possible if you can do one or more of the following things.

   a. Exploit inherent advantages of Clean Coal Technology in that market, and Clean Coal Technology applications benefiting that market. For example:
      - Promote the environmental performance advantages of Clean Coal Technologies in a truly strict environmental regulatory situation.
      - Match up a small coal gasifier feeding a super-efficient multiple fuel cell/small combustion turbine combined cycle.

- Combine a low or zero-value feedstock, a syngas-derivable product with a market need, and synergies between the gasification and the syngas upgrade processes.
- Look for fuel flexibility, sitability and "trigeneration" (Powerplex, Coalplex) opportunities.

b. Anticipate and exploit the factors beyond your control that heavily influence the business attractiveness of a Clean Coal Technology application. For example:
   - Change in relative prices of coal vs. gas.
   - Change in relative capital costs of Clean Coal Technology vs. natural gas/combined cycle - a gap likely to close as Clean Coal Technologies mature.
   - Change in relative thermal efficiency of Clean Coal Technology vs. natural gas/combined cycle.
   - Sudden regulatory change that defines new rules of the game.

c. Allocate risk rationally and mutually satisfactorily, in a way that avoids future second-guessing.

2. Learn from your (and others') false starts.

3. Package the offering right with the customer in mind. You can depend on innovation in a new market passing through three stages of customer response:

   a. "I don't like it."
   b. "What is it?"
   c. "I want one!"

LUNCHEON

Climate Change

CLIMATE CHANGE

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PAPER UNAVAILABLE AT TIME OF PRINTING

For copies of the paper contact the presenter.

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